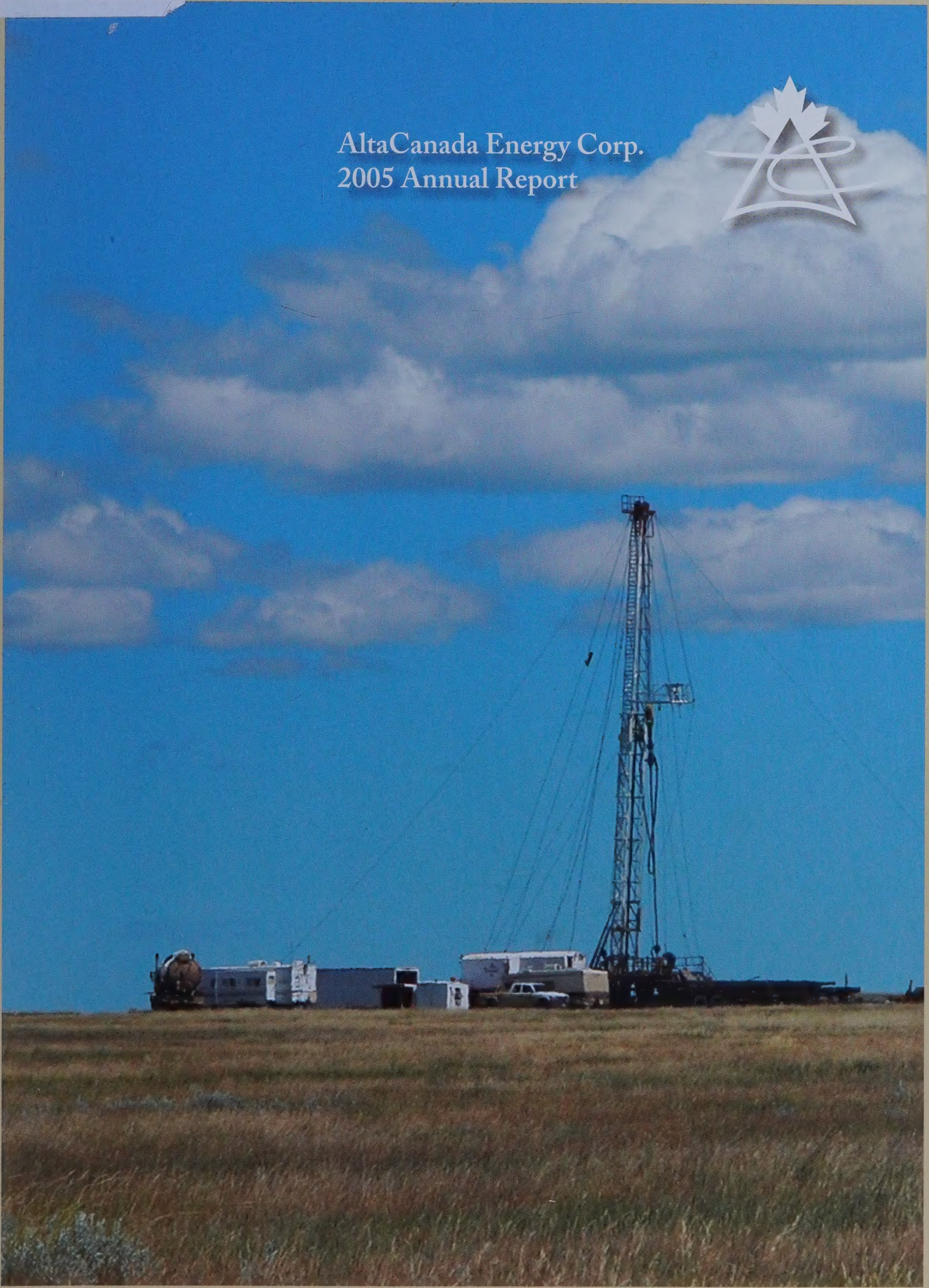

AltaCanada Energy Corp.
2005 Annual Report

ABBREVIATIONS

AECO	Alberta Energy Company; (reference price for natural gas)
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet per day
ARTC	Alberta Royalty Tax Credit
MMcf	Million cubic feet
Bbl	Barrel(s)
MMBtu	Million British Thermal Unit
Bbls/d	Barrels per day
NGL	Natural gas liquids
BOE	Barrels of oil equivalent
NIT	Nova Inventory Transfer
CDN	Canadian
US	United States
GJ	Gigajoule
WTI	West Texas Intermediate, (oil reference price set at Cushing, Oklahoma)
MBbl	Thousand barrels
MBOE	Thousand barrels of oil equivalent

Cover: Montana Drilling
Photograph by Roger Baines

Notice of Annual & Special Meeting

AltaCanada Energy Corp. invites its shareholders and interested parties to attend its annual and special meeting to be held on May 18, 2006 at 3:00 pm at the Calgary Petroleum Club, 319 5th Avenue SW, Calgary, Alberta. Shareholders who are unable to attend are encouraged to complete and return the proxy included with the Notice of Meeting and Information Circular mailed with the annual report. Copies of corporate information may be obtained by contacting:

AltaCanada Energy Corp.
2100, 101 – 6th Avenue SW
Calgary, Alberta, Canada,
T2P 3P4

Tel: 403.265.9091
Fax: 403.265.9021
Email: info@altacanada.com
Web: www.altacanada.com

ADVISORY – Readers are cautioned that assumptions used in the preparation of the annual report may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted, as a result of numerous known uncertainties, and other factors, many of which are beyond the control of the Corporation. These risks include, but are not limited to: the risks associated with the oil and gas industry, commodity prices and exchange rate changes. Industry related risks include but are not limited to: operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production costs and expenses. The risks outlined above should not be considered exhaustive. The reader is cautioned not to place undue reliance on this forward-looking information. The Corporation undertakes no obligation to update or revise any forward-looking statements except as required by applicable securities laws.

Corporate Information

CORPORATE OFFICERS

Donald E. Foulkes
President and Chief Executive Officer

Charles V. Selby
Chairman and Chief Financial Officer

Donald L. Jackson
Executive Vice-President and
Chief Operating Officer

William E. Brimacombe
Vice-President, Finance

ADDITIONAL TEAM MEMBERS

Catherine Bjorndalen, Controller
Roger Baines, Senior Geologist
Sharon Cooper, Land Manager
Dale Stoodley, Operations Manager

LEGAL COUNSEL

Gowling Lafleur Henderson LLP
Calgary, Alberta

BANKERS

TD Canada Trust
Calgary, Alberta

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Inquiries regarding changes of address, registered shareholdings, stock transfers or lost certificates should be directed to:

Computershare Trust Company of Canada
Attention: Stock Transfer Department

630, 530—8th Avenue SW
Calgary, Alberta T2P 3S8
Tel: 403.267.6555 Fax: 403.267.6529

STOCK EXCHANGE

The TSX-V Venture Exchange, symbol: ANG

VOLUME REPORTING

Where volumes are reported in barrels of oil equivalent, gas is converted to oil at six thousand cubic feet per barrel, unless otherwise stated. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf : 1 Bbl is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

FINANCIAL REPORTING

All amounts are in Canadian dollars, unless otherwise stated. The Corporation's fiscal year-end is December 31.

Highlights

	2005	2004	2003
FINANCIAL			
Total Revenue ($)	**12,507,106**	6,413,355	7,531,873
Cash Flow from Operations ($)	**5,226,412**	2,177,314	3,088,016
Per Common Share ($) - Basic/Diluted	**0.09**	0.04	0.07
Net Earnings (Loss) ($)	**1,069,758**	(443,426)	305,189
Per Common Share ($) - Basic/Diluted	**0.02**	(0.01)	0.01
Capital Expenditures ($)	**12,101,006**	13,546,492	13,937,426
Bank Indebtedness ($)	**6,587,940**	3,596,317	2,956,620
Shareholders' Equity ($)	**25,438,738**	23,817,571	19,039,980
Total Assets ($)	**44,011,639**	36,359,728	28,551,221
Common Shares - (weighted average for year)			
Basic	**59,957,912**	54,240,403	42,467,288
Diluted	**60,014,715**	56,417,424	45,605,295
Common Shares - (outstanding December 31)	**60,017,844**	59,488,251	51,983,024
OPERATIONS			
Average Daily Production:			
Natural Gas (Mcf/d)	**3,357**	1,904	2,381
Oil and NGLs (Bbls/d)	**105**	132	177
Total (BOE/d)	*** 664**	449	574
% Gas/Oil Ratio	**84/16**	71/29	69/31
Average Prices:			
Natural Gas ($/Mcf)	**8.81**	6.48	6.08
Oil and NGLs ($/Bbl)	**40.65**	34.80	29.90
Total ($/BOE)	**50.95**	37.72	34.45
RESERVES (Proved Plus Probable)			
Montana			
Natural Gas (MMcf)	**16,515**	8,368	-
Oil and NGLs (MBbls)	**-**	-	-
Total (MBOE)	**2,752**	1,395	-
Present Value ($ discounted at 10%)	**36,370,000**	11,370,000	-
Canada			
Natural Gas (MMcf)	**3,513**	4,489	5,766
Oil and NGLs (MBbls)	**346**	433	497
Total (MBOE)	**932**	1,181	1,458
Present Value ($ discounted at 10%)	**13,880,000**	14,860,000	14,493,000
Total			
Natural Gas (MMcf)	**20,028**	12,857	5,766
Oil and NGLs (MBbls)	**346**	433	497
Total (MBOE)	**3,684**	2,576	1,458
Present Value ($ discounted at 10%)	**50,250,000**	26,230,000	14,493,000
UNDEVELOPED LAND			
Gross Acres	**226,771**	247,498	251,331
Net Acres	**191,956**	189,253	197,266
WELLS DRILLED			
Gross	**38.0**	56.0	26.0
Net	**34.0**	28.5	13.7
Gross Success Rate (%)	**73.7**	78.6	61.5

*Production rate reported on January 9, 2006 was 823 BOE/d and production levels reached 1,300 BOE/d as reported by press release on March 9, 2006.

Chairman's Message

AltaCanada's prime assets remain the land and production base in Blaine County, Montana and the talented staff to implement growth.

Excellent progress was made by AltaCanada in 2005 in Montana and Canada. In Montana, we have materially added to natural gas reserves and production has increased substantially to recent levels of just below 6 MMcf/d. With our increased experience, AltaCanada is drilling higher productivity wells enhancing the value of our play. Our 200,000 acre core area, and recent adjacent land acquisitions, will continue to provide many drilling opportunities.

In Canada, our strategy of selling non-core assets into a premium priced property market allowed us to create value from a very diverse low working interest asset base. Proceeds from sales of these properties were applied to our Montana opportunities, enabling us to significantly add to the value of the Corporation. Our five remaining Canadian assets have long life production and four areas have significant infill drilling opportunities. Despite the $2.7 million in Canadian property sales (80 BOE/d) during 2005, our Canadian asset value remained stable.

AltaCanada's prime assets are our land and production base in Blaine County, Montana and our talented and experienced staff committed to achieving growth. During November and December of 2005, a series of land sale successes created a significant addition to our prospective Montana acreage and will permit an expanded focus for 2006. Our Montana reserve base increased from 8.4 BCF to 16.5 BCF during 2005 and we estimate significant further increases will result from a drilling program of over 60 wells in 2006.

Our production continues to climb. Our average production rate for 2005 was 664 BOE/d (up from 449 BOE/d in 2004). On January 9, 2006, our production was reported at 823 BOE/d. With completions and tie-ins during February, production climbed to 1,300 BOE/d by March 9, 2006. Our 2006 production is expected to continue to climb in line with our corporate objective of drilling 15 Montana wells each quarter.

Fourth quarter 2005 financial results are highlighted in this report. The combination of growing production and record pricing added significant revenue and cash flow.

Growth in 2005 was accomplished, without an equity issue, through increased cash flow, a successful hedging program, Canadian property sales and a modest increase in debt. This materially increased our asset value on a per share basis.

Charles V. Selby
Chairman, Chief Financial Officer and Director
March 30, 2006

Montana 2005 Highlights

All of our Montana activities are conducted by our 100% owned subsidiary, Montana Land & Exploration, Inc. (ML&E). All drilling activity is focused in Blaine County.

ML&E had a great year:

- Drilled 34 (32.31 net) shallow Eagle Formation wells, completing 26 (25.0 net);
- Doubled proved plus probable Montana gas reserves from 8.4 BCF to 16.5 BCF;
- Built two new pipeline gathering systems providing increased take away capacity and much shorter tie-in distances to each of three gathering lines and facilities;
- Increased production from 1.3 MMcf/d in January 2005 to 3.0 MMcf/d in January 2006 and at March 9, 2006 to 5.8 MMcf/d;
- Increased our land base to over 200,000 net acres and started a significant extension of our play to the southeast on the Fort Belknap Indian Reservation;
- Built our drill-ready inventory to 125 wells.

Full cycle exploration can reasonably be expected to take 3 years. AltaCanada closed its first Montana acquisition in March 2003. Our knowledge and confidence in the Eagle play has continued to grow over the three years as wells are drilled and additional geophysical data is acquired.

Our 2006 program is expected to include 15 shallow Eagle wells each quarter within our 200,000 plus acres core area adjacent to three gathering pipelines. Five or more exploratory tests are expected to extend this knowledge base on a new exploration trend to the southeast, probably in the third quarter.

Over the past three years we have drilled 75 Eagle wells (1,200'± depth) with 60 successfully completed and 45 presently tied-in and producing. Only in the last six months have we started looking at the deeper formations in the area, including the Jurassic Sawtooth at 4500' depth. This prospective formation has produced 14 million barrels of oil immediately adjacent to our lands in 5 separate pools.

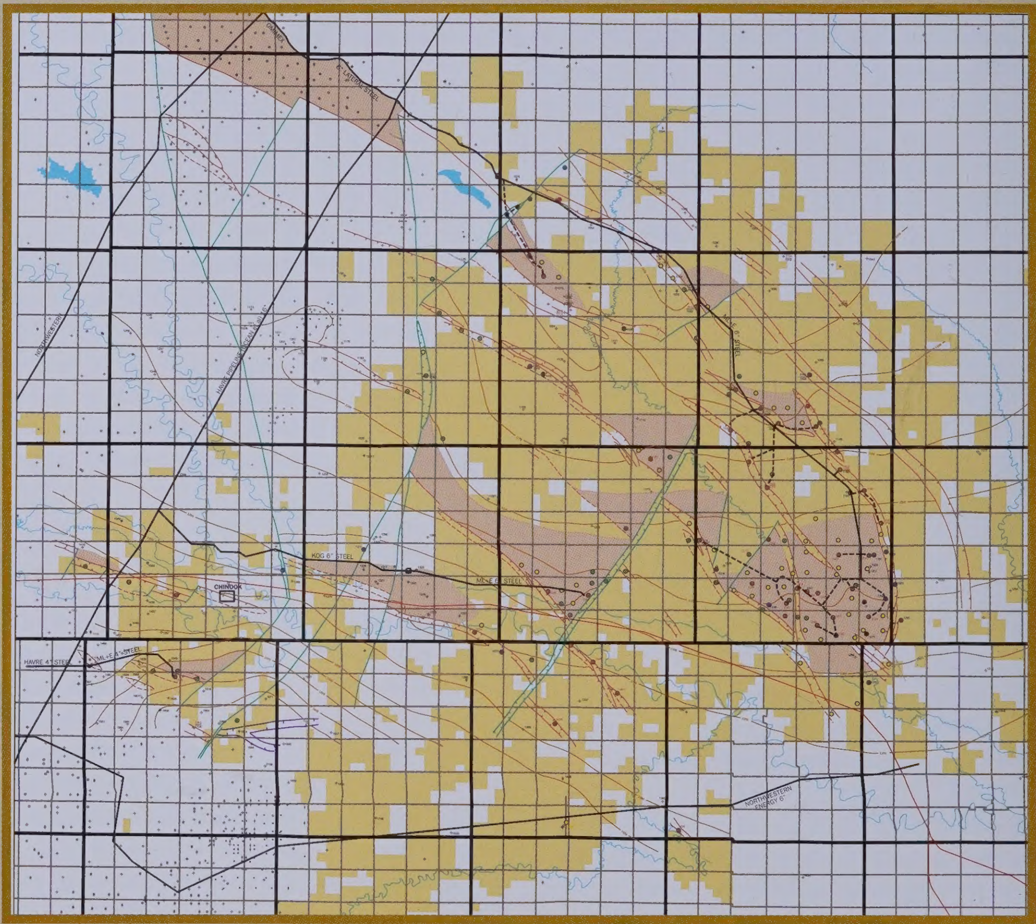
In December 2005, one Jurassic test was non-productive and early in 2006 two non-operated Jurassic tests are scheduled. This deeper play is complicated by the velocity changes resulting from the Eagle level faulting which we are successfully understanding. During 2006 we hope to continue to unravel the deeper structures, 14 of which have been identified on our lands using our existing seismic database.

Eagle Production

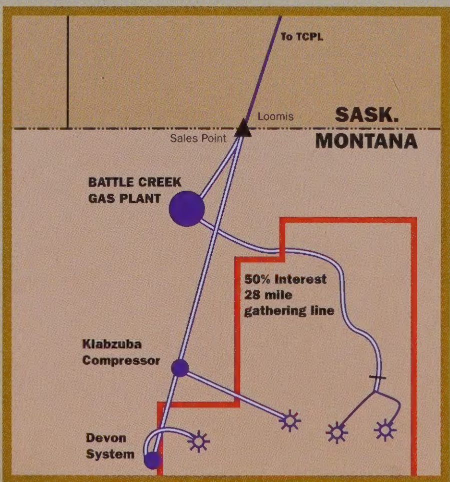
The Eagle sandstones are the stratigraphic equivalent of the Milk River sands of southeast Alberta and southwest Saskatchewan and provide our principal objective. On the Canadian side, Canadian technology, developed from several thousand wells, has extended this shallow gas play to the distal limits of tighter sandstones and siltstones. Drilling costs have been progressively lowered (coiled tubing applications) and flow rates have been improved by low water loss drilling muds and fracture techniques. All of this can, and will, be applied in Blaine County.

Blaine County is both a conventional sand play and a tight sand reservoir. On the west side of our block, we have great quality reservoirs with over 100 ft of sand yielding 500 Mcf/d unfrac'd. On the east side progressively tighter sands are present and require significant "fracs" to produce 30 to 100 Mcf/d. Additionally, Blaine County has an important structural component providing our "pop-up" targets with significant natural fracturing that increase production from the reservoirs. Some pop-ups are as shallow as 800' and because of over pressurizing (600 lbs vs 400lbs) have been drilled and completed using air to minimize well bore damage and to deal with substantial flowrates.

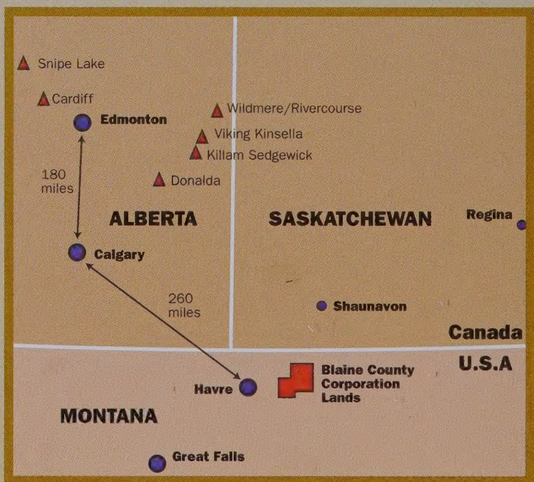
The geophysical techniques we have developed work well to locate our drilling targets and have kept our success ratios high.



Blaine County, Montana holdings



Pipeline Map



Locator Map

Drilling cost control is important for shallow gas plays. Our costs to drill and case to 1,200' depth have increased with increased costs for steel and cement, but we still average only USD$90,000 for a cased well.

Montana Operations and Environment

Blaine County is a great place to explore and operate. Through ML&E, we have worked hard at maintaining our relationships with land owners, royalty and lease holders, the Bureau of Land Management and our contractors. Our use of satellite technology, for monitoring all of our wells and compressors gives us instant access to well data, (production rates, pressures and temperature), maximizes control and reliability of information and, most importantly, minimizes trips to the wellhead. Our policy of minimal disturbance drilling greatly reduces our footprint at well sites. Our produced water, because of its very low salinity, becomes an asset to area ranches. Our efforts are appreciated by our surface owner partners and the efforts of our operating staff and contractors in all environmental matters is greatly valued.

Marketing

All of ML&E's production is marketed at the "Loomis" Saskatchewan border point at a premium to the "AECO Daily or Monthly" index price for all three of our gathering systems. Our ability to take our proceeds in US or CDN dollars provides a natural currency hedge to our continued re-investment in Blaine County.

Montana Outlook

16.5 BCF of proved plus probable gas reserves and the current production rate of 5.8 MMcf/d clearly validate the merit of our acreage purchase three years ago. Our inventory of drilling locations, presently approximately 125 wells, continues to grow and our reserve life index of 16 years (proved plus probable) further encourages an aggressive drilling program.

It is with confidence we are eager to continue with the next 60 Montana wells during 2006.

Donald E. Foulkes
President, Chief Executive Officer and Director
March 30, 2006

Alberta Operations Review

In 2005 our the primary focus was directed towards exploration and exploitation of the Blaine County, Montana assets. Even though minimal capital was expended in Canada, significant steps were taken to enhance the Canadian assets which included the rationalization of some of the minor, high operating cost properties and the continuation of drilling success at Cardiff.

Property Rationalization

In 2005, there was substantial third party interest, both large and small companies, in purchasing producing assets. In this buyer-rich environment AltaCanada chose to dispose of several minor working interest, higher operating cost properties at Hamilton Lake, Rivercourse and Joffre and also chose to sell our operated interests at Donalda, Alberta at a sale price far in excess of the appraised value. In total, these properties were sold for a cash consideration of $2.7 million allowing the Corporation to direct additional capital to the rapidly growing Montana assets. The loss of 80 BOE/d in Canada by these sales was replaced several fold by production increases in Montana.

Cardiff

Cardiff is the Corporation's most active area in Canada and the Corporation now owns an average 47 percent working interest in 12,480 acres. During 2005, AltaCanada participated in the drilling of three wells at an average 40 percent interest resulting in two (1.0 net) gas wells and one (0.2 net) abandoned well.

One Cardiff well, in which AltaCanada held a 15 percent royalty interest, we estimate, reached payout in December and converted to a 50 percent working interest thereby increasing the Corporation's net production by 500 Mcf/d.

AltaCanada's net production from Cardiff increased 23 percent over the year from 870 Mcf/d to 1,070 Mcf/d in January 2006. Plans for 2006 include the drilling of at least two wells on joint lands with our partners. In addition, drilling by third parties, currently underway on lands which offset the Corporation's 100 percent owned acreage may lead to additional drilling targets.

Viking Kinsella

AltaCanada controls interests averaging 41 percent in 18,000 acres at Viking Kinsella, including over 35 producing wells, a 58.4 percent interest in a gas processing facility and varying interests between 44.5 percent and 49.5 percent in an extensive gas gathering system.

No wells were drilled on this property during 2005; however, at year end AltaCanada began negotiations with a third party to conduct a multi-well drilling program on the acreage to be completed at no cost to the Corporation. Details will be provided at a later date if a transaction is completed.

AltaCanada continues to evaluate a 50 percent working interest well drilled in 2003 in the northern portion of this property that set up a Sparky oil development project. Although the well also tested 700 Mcf/d from the Lloydminster sand, below the Sparky zone, difficulty in putting the well on production was caused by heavy oil produced in association with the gas. Remedial measures this January, including the installation of a bottom hole progressive cavity pump, so far have not been successful and the well will likely be re-completed into the Sparky oil zone this year. Subject to further production testing, seismic, logs and offset well data there is potential for an 11 well infill development program to exploit the heavy Sparky oil.

Killam

AltaCanada owns varying interests in 28,000 acres at Killam, Alberta. The Corporation holds an average working interest of 16.8 percent in about 8,300 acres and royalty interests ranging from 2.1 percent to 8.4 percent in the balance of the land. There are several opportunities to enhance the Viking production through a combination of infill drilling and well stimulation.

Snipe Lake

The Snipe Lake 3-28 gas well was placed on production March 1, 2005 from the Gething and Fahler zones. Because of concerns about potential depletion and the capital needs of Montana, AltaCanada elected not to participate in a $1 million pipeline to place this single well on production. After recovery of 200 percent of the pipeline capital costs by the builder of the pipeline, the Corporation will revert to its 30 percent working interest in the production. Our estimates, to be confirmed by the operator of the well, suggest that the well paid out during December 2005. Although the Fahler zone depleted shortly after start-up of production, the Gething zone continues to produce between 500 to 750 Mcf/d, which will provide an additional 25 to 38 BOE/d net to the Corporation's 30 percent interest, once payout is confirmed.

Wildmere Lloydminster Unit No 1.

The Wildmere Lloydminster Unit No. 1, operated by Husky Oil, is AltaCanada's primary oil producing property. This Unit, in which AltaCanada owns a 5.1572 percent interest produces over 2,100 BBls/d of medium heavy crude. Future plans for this Unit include well optimizations and potentially the drilling of 15 more oil well locations and three injectors.

Donald L. Jackson
Executive Vice-President and Chief Operating Officer
March 30, 2006

Management's Discussion & Analysis

"Management's Discussion and Analysis" is dated March 30, 2006 and should be read in conjunction with the audited financial statements for the year ended December 31, 2005 for a full understanding of the financial position and results of operations of the Corporation.

Forward Looking Statements

Certain information regarding AltaCanada Energy Corp. "the Corporation" or "AltaCanada" set forth in this document, including management's assessment of the Corporation's future plans and operations contains forward looking statements that involve substantial known and unknown risks and uncertainties. By their very nature, these forward statements are subject to numerous risks and uncertainties, certain of which are beyond Management's control. Actual results could differ materially from those currently anticipated due to any number of factors including such variables as new information regarding recoverable reserves, volatility of commodity prices, competition from other producers, environmental, legislative, regulatory and political changes along with other factors discussed in our annual report. Accordingly, no assurance can be given that any events anticipated by the forward looking statements will transpire or occur, or if any of them do, what the impact to the Corporation might be.

Basis of Presentation

The financial results discussed below include the results of AltaCanada Energy Corp. and its wholly owned subsidiaries Alberta Selecta Corporation (ASC), ANG Holding Corp., ANG Holding (USA) Corp., and Montana Land and Exploration, Inc. (ML&E) and AltaCanada Energy Partnership formed June 1, 2003 by ANG and ASC.

The financial data presented below has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel equivalent ("BOE") using six thousand cubic feet of natural gas equal to one barrel of oil.

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited annual Consolidated Financial Statements and accompanying notes.

Certain comparative figures have been reclassified or restated to conform with current year presentation.

Non-GAAP Measures

Cash flow from operations, and cash flow from operations per share basic and diluted, Earnings before interest expense and income taxes (EBIT), and Earnings before interest expense, income taxes and depletion, depreciation and accretion (EBITDA), are not measures that have any standardized meaning prescribed by GAAP and are considered non-GAAP measures. Therefore, these non-GAAP measures may not be comparable to similar measures presented by other issuers. These non-GAAP measures have been described and presented in this MD&A to provide shareholders and potential investors with additional information regarding the Corporation's liquidity and its ability to generate funds to finance its operations. Management uses cash flow from operations, EBIT and EBITDA as key measures to assess the Corporation's ability to finance the operating activities and capital expenditures.

Critical Accounting Estimates

Depletion and Depreciation Expense

The Corporation uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized on a country by country basis, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion and depreciation expense. Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion, until reserves have been moved to the proved category. These properties are reviewed quarterly to determine if proved reserves have been assigned, at which point they would be included in the depletion calculation. If impairment exists any write-down would be charged to depletion and depreciation expense.

Full Cost Accounting Ceiling Test

Oil and gas assets are evaluated at least annually to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the oil and gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

Asset Retirement Obligation

The Corporation records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets for the period in which they are incurred, when the asset is purchased or developed. On recognition of the liability, there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost. The total future asset retirement obligation is an estimate based on the Corporation's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligation is an estimate that is subject to measurement uncertainty and any change would impact the liability.

Income Taxes

The determination of the Corporation's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

Other Estimates

The accrual method of accounting requires management to incorporate certain estimates including estimates of revenues, royalties, and production costs as at a specific reporting date but for which actual revenues and expenses have not yet been invoiced or received, and estimates on capital projects which are in progress or recently completed where actual costs have not been received at a specific reporting date. The Corporation ensures that individuals with the most knowledge of the activity are responsible for the estimates. These estimates are compared to actual results in order to make informed decisions on future estimates.

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment, and the provision for asset retirement obligation costs, are based on estimates. In addition, the ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Risk Assessment

There are a number of risks facing participants in the oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following reviews the general and specific risks and includes AltaCanada's approach to managing these risks.

Exploration, Development and Production Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration will result in new discoveries of oil and natural gas in commercial quantities.

The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that AltaCanada will be able to continue to locate satisfactory properties for acquisition or participation. Current market conditions, terms of acquisition and participation or pricing conditions may make such acquisitions or participations uneconomical.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, completion and operating costs. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations mitigate these risks, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Prices, Markets and Marketing

Demand for crude oil and natural gas produced by the Corporation exists within North America, however, crude oil prices are affected by worldwide supply and demand fundamentals, while natural gas prices are affected by North American supply and demand fundamentals, all of which are beyond the control of the Corporation. Prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in oil and natural gas prices, leading to a reduction in the volume of oil and gas reserves.

The Corporation may also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in future net production revenue. Debt available to the Corporation is in part determined by the borrowing base of the Corporation and a material decline in prices from historical average prices could limit the borrowing base, reducing the bank credit available or could require that a portion of any existing bank debt be repaid.

In addition to establishing markets for its oil and natural gas, the Corporation must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas, which may be acquired or discovered, will be affected by numerous factors beyond the Corporation's control. AltaCanada will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced. The ability to market natural gas may depend upon the Corporation's ability to acquire pipeline space to deliver natural gas to commercial markets.

The Corporation will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production and many other aspects of the oil and natural gas business. The Corporation has limited direct experience in the marketing of oil and gas and uses the expertise of a marketing consultant.

Inflation Risks

Inflation risks expose the Corporation to potential erosion of product netbacks. For example, prices for oil and natural gas production equipment and services can inflate the costs of operations.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation which could result in a reduction of the revenue.

Substantial Capital Requirements

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If revenues or reserves decline the Corporation may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt

or equity financing, or cash generated from operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms that are acceptable. Future activities may require the Corporation to alter its capitalization significantly. The inability to access sufficient capital for its operations could have a material adverse effect on AltaCanada's financial condition, results of operations or prospects.

Lenders have been provided with collateral over substantially all of the assets of the Corporation. If AltaCanada becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose or sell its properties. The proceeds of any such sale would be applied to satisfy amounts owed to lenders and other creditors and only the remainder, if any, would be available to shareholders.

Additional Funding Requirements

Cash flow from the Corporation's reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to miss certain acquisition opportunities and reduce or terminate its operations. If revenues from its reserves decrease as a result of lower oil and gas prices, it will affect the Corporation's ability to expend the capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms that are acceptable.

The Corporation may enter into transactions to acquire assets or shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase debt levels above industry standards. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that AltaCanada may incur. The level of the Corporation's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Competitive Industry Conditions

The North American oil and natural gas industry, especially in western Canada, has become a very competitive industry for oil and gas properties, undeveloped land, drillable prospects and oil and gas industry professionals. The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce these reserves in an economic and timely fashion. In periods of increased activity these services and supplies can become difficult to obtain. The Corporation mitigates this risk by developing strong long-term relationships with suppliers and contractors and maintaining close working relationships with industry partners.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and

liability and potentially increased capital expenditures and operating costs. No assurance can be given that environmental laws will not result in a curtailment of production or material increase in the costs of production, development or exploration activities or otherwise adversely affect financial condition, results of operations or prospects.

Insurance

The Corporation's involvement in the exploration for and development of oil and oil and gas properties may result in the Corporation becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although the Corporation has obtained insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation's financial position, results of operations or prospects.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gas emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with proposed provincial reduction requirements, may require the reduction of emissions or emissions intensity produced by the Corporation's operations and facilities. The direct or indirect costs of these regulations may adversely affect the Corporation's Canadian business.

The United States is not a signatory to the Kyoto Protocol.

Dividends

To date, AltaCanada has not paid any dividends on the outstanding Common Shares and does not anticipate the payment of any dividends on the Common Shares for the foreseeable future.

Reliance on Key Personnel

The success of the Corporation depends in large measure on certain key personnel. The Corporation does not have key man insurance in effect for management, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Corporation. In addition, the competition for qualified personnel in the oil and gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of our business. In Canada, where AltaCanada is not the operator of its oil and gas properties, it will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators.

Conflicts of interest

Certain members of our board of directors are also directors and officers of other oil and gas companies and conflicts of interest may arise between their duties as directors of AltaCanada and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to, such other procedures and remedies as applicable under the Alberta Business Corporations Act.

Evaluation of Disclosure Control and Procedures

The Chief Executive Officer, Donald Foulkes and the Chief Financial Officer, Charles Selby, evaluated the effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2005 and concluded that the disclosure controls and procedures were effective to ensure that information the Corporation is required to disclose in its annual filings, interim filings or other reports (each as defined in National Instrument 52-109 of the Canadian Securities Administrators) filed or submitted by it under provincial securities legislation is recorded, processed, summarized and reported within the time periods specified in the provincial securities legislation and to ensure that information required to be disclosed by AltaCanada in its annual filings, interim filings or other reports filed or submitted under provincial securities legislation is accumulated and communicated to management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The evaluation took into consideration the functioning of its executive officers, board of directors and board committees. In addition, the evaluation covered processes, systems and capabilities relating to regulatory filings, public disclosures and the identification and communication of material information.

Overview

AltaCanada's 2005 total capital spending was $12.1 million, of which $10.2 million relates to the further commercialization of our Montana properties through exploration and development, additions to infrastructure and the expansion of our land base. Total capital expenditures were funded through cash flow from operations of $5.2 million, Canadian property dispositions of $2.7 million, bank indebtedness of $3.0 million and an increase in working capital deficiency of $1.2 million.

During the year AltaCanada continued its transition to a Montana-focused operating Corporation by rationalizing $2.7 million in non-core Canadian assets while expanding our gas play in northern Montana. This transition increased production volumes, and combined with strong commodity prices throughout 2005, increased revenues and cash flow from operations compared to the prior year. Cash flow from operations more than doubled to $5.2 million in 2005 from $2.2 million in 2004. Total revenue increased 95 percent to $12.5 million in 2005 from $6.4 million in 2004.

In 2005, the Corporation increased total reserves by 22 percent on a proved basis and by 43 percent on a proved plus probable basis. These reserve additions do not include significant undeveloped resources. The Corporation anticipates considerable reserves will be added from drilling throughout 2006. The present value before tax of proved plus probable reserves, discounted at 10 percent, increased 92 percent in 2005 to $50.3 million up from $26.2 million in 2004, largely due to the $36.4 million before tax value placed on Montana reserves at year end.

Production Summary

	December 31 - Exit		Average Daily Production		
	2005 *	2004	**2005**	2004	2003
Natural Gas (Mcf/d)	**3,647**	3,360	**3,357**	1,904	2,381
Crude Oil (Bbls/d)	**93**	120	**105**	132	177
Total Production (BOE/d)	**701**	680	**664**	449	574
Annual Production (BOE)			**242,470**	164,334	209,500

* Production reached 823 BOE/d January 9, 2006.

Segmented Production Summary

	Year ended December 31, 2005			Year ended December 31, 2004		
Average Daily Production	**Montana**	**Canada**	**Total**	Montana	Canada	Total
Natural Gas (Mcf/d)	**1,789**	**1,568**	**3,357**	256	1,648	1,904
Crude Oil (Bbls/d)	**–**	**105**	**105**	–	132	132
Total Production (BOE/d)	**298**	**366**	**664**	43	406	449
Annual Production (BOE)	**108,801**	**133,669**	**242,470**	15,738	148,596	164,334

Overall, AltaCanada's average daily production increased 48 percent to 664 BOE/d, up from 449 BOE/d in 2004. Natural gas production improved 76 percent to 3,357 Mcf/d in 2005 from 1,904 Mcf/d in 2004. Crude oil and natural gas liquids sales volumes decreased 20 percent to 105 BBls/d from 132 BBls/d in 2004. Increases in production reflect a full year of Montana gas production that commenced October 1, 2004 combined with the 2005 drilling program which added 34 wells in Montana and 4 wells in Canada. These increases were marginally offset by natural declines and by Canadian property dispositions of 80 BOE per day.

During 2005, the Snipe Lake production facility and one well at Cardiff were placed on production with AltaCanada's interest in a "Before Payout" status. At year-end both wells were near to an "After Payout" position, with AltaCanada holding a working interest of 30 percent in Snipe Lake and a 50 percent interest in the new Cardiff well. Once payout is confirmed this will add between 30 and 50 BOE/d to our production in early 2006.

Segmented Exit Production Summary

	Exit December 31, 2005 *			Exit December 31, 2004		
Average Daily Production	**Montana**	**Canada**	**Total**	Montana	Canada	Total
Natural Gas (Mcf/d)	**2,346**	**1,301**	**3,647**	1,680	1,680	3,360
Crude Oil (Bbls/d)	**–**	**93**	**93**	–	120	120
Total Production (BOE/d)	**391**	**310**	**701**	280	400	680

* Production reached 823 BOE/d January 9, 2006.

Selected Quarterly Summary

For the year ended December 31, 2005 ($, except otherwise stated)	Q1	Q2	Q3	Q4	Total
Production:					
Natural Gas (Mcf/d)	3,003	3,542	3,463	3,414	3,357
Oil and NGLs (Bbls/d)	115	81	101	123	105
Total (BOE/d)	616	671	678	692	664
Average Prices:					
Natural Gas ($/Mcf)	6.75	7.08	9.45	11.71	8.81
Oil and NGLs ($/Bbl)	34.56	44.15	49.61	36.61	40.74
Total ($/BOE)	39.37	42.69	55.66	64.29	50.95
Revenue	2,180,837	2,607,773	3,035,376	4,683,120	12,507,106
Royalties	(420,912)	(437,509)	(822,080)	(1,038,961)	(2,719,462)
Operating Expenses	(633,244)	(391,045)	(293,366)	(768,862)	(2,086,517)
Operating Income	1,126,681	1,779,219	1,919,930	2,875,297	7,701,127
General and Administrative	(359,808)	(411,195)	(273,003)	(445,419)	(1,489,425)
Interest	(294,945)	(226,192)	(96,829)	(218,086)	(836,052)
Stock Based Compensation	(113,733)	(75,450)	(153,687)	(69,083)	(411,953)
Depletion, Depreciation and Accretion	(895,092)	(978,019)	(830,451)	(1,174,999)	(3,878,561)
Other	(161,076)	11,295	54,681	(28,541)	(123,641)
Earnings (Loss) before Income Taxes	(697,973)	99,658	620,641	939,169	961,495
Current Income Tax (Expense)	-	-	-	(94,627)	(94,627)
Future Income Tax Recovery (Expense)	271,302	(38,736)	(241,244)	211,568	202,890
Net Earnings (Loss)	(426,671)	60,922	379,397	1,056,110	1,069,758
Per Share - Basic	(0.01)	0.00	0.01	0.02	0.02
Per Share - Diluted	(0.01)	0.00	0.01	0.02	0.02
Net Earnings (Loss)	(426,671)	60,922	379,397	1,056,110	1,069,758
Non-Cash Items:				-	
Depletion, Depreciation and Accretion	895,092	978,019	830,451	1,174,999	3,878,561
Stock Based Compensation	113,733	75,450	153,687	69,083	411,953
Unrealized Hedging Loss (Gain)	215,586	-	395,348	(636,536)	(25,602)
Future Income Tax Expense (Recovery)	(271,302)	38,736	241,244	(211,568)	(202,890)
Other	161,076	(11,295)	(70,582)	15,433	94,632
Cash Flow from Operations	687,514	1,141,832	1,929,545	1,467,521	5,226,412
Per Share - Basic	0.01	0.02	0.03	0.03	0.09
Per Share - Diluted	0.01	0.02	0.03	0.03	0.09

Fourth quarter production of 692 BOE/d is consistent with the previous quarter's production of 678 BOE/d. The Corporation's commodity prices increased 16 percent in the fourth quarter compared to the third quarter of 2005. Price increases in the last quarter of 2005 improved revenues 18 percent or $0.6 million (excluding the impact of hedging). Cash flow, however decreased 24 percent or $0.5 million compared to the third quarter of 2005. Reduced fourth quarter cash flow is the result of increased general and administrative costs related to audit and tax preparation fees, increased interest related to Part XXII.2 penalties and interest and higher operating costs (fuel gas) in Montana that were recorded in the fourth quarter.

For the year ended December 31, 2004 ($, except otherwise stated)	Q1	Q2	Q3	Q4	Total
Production:					
Natural Gas (Mcf/d)	2,121	1,580	1,428	2,465	1,904
Oil and NGLs (Bbls/d)	136	157	125	109	132
Total (BOE/d)	490	420	363	520	449
Average Prices:					
Natural Gas ($/Mcf)	6.01	7.04	6.54	6.56	6.48
Oil and NGLs ($/Bbl)	34.34	32.55	40.21	32.81	34.80
Total ($/BOE)	35.59	38.61	39.56	37.97	37.72
Revenue	1,522,468	1,480,351	1,341,241	2,069,295	6,413,355
Royalties	(344,654)	(260,913)	(210,972)	(432,132)	(1,248,671)
Operating Expenses	(424,930)	(238,106)	(315,992)	(376,280)	(1,355,308)
Operating Income	752,884	981,332	814,277	1,260,883	3,809,376
General and Administrative	(235,233)	(267,394)	(218,901)	(418,558)	(1,140,086)
Interest	(59,663)	(64,785)	(82,512)	(51,130)	(258,090)
Stock Based Compensation	(81,744)	(101,810)	(61,407)	(58,152)	(303,113)
Depletion, Depreciation and Accretion	(666,016)	(607,294)	(518,865)	(744,366)	(2,536,541)
Other	(12,559)	(8,776)	31,732	14,343	24,740
Earnings (Loss) before Income Taxes	(302,331)	(68,727)	(35,676)	3,020	(403,714)
Current Income Tax (Expense)	-	-	-	(54,037)	(54,037)
Future Income Tax Recovery (Expense)	101,644	23,106	11,994	(122,419)	14,325
Net Earnings (Loss)	(200,687)	(45,621)	(23,682)	(173,436)	(443,426)
Per Share - Basic	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)
Per Share - Diluted	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)
Net Earnings (Loss)	(200,687)	(45,621)	(23,682)	(173,436)	(443,426)
Non-Cash Items:					
Depletion, Depreciation and Accretion	666,016	607,294	518,865	744,366	2,536,541
Stock Based Compensation	81,744	101,810	61,407	58,152	303,113
Unrealized Hedging Loss (Gain)	72,290	(31,792)	(40,567)	(215,517)	(215,586)
Future Income Tax Expense (Recovery)	(101,644)	(23,106)	(11,994)	122,419	(14,325)
Other	3,123	11,899	4,752	(8,777)	10,997
Cash Flow from Operations	520,842	620,547	508,781	527,207	2,177,314
Per Share - Basic	0.01	0.01	0.01	0.01	0.04
Per Share - Diluted	0.01	0.01	0.01	0.01	0.04

In the fourth quarter of 2005, average production increased 33 percent to 692 BOE/d up from 520 BOE/d in the fourth quarter of 2004. The Corporation's realized commodity prices also strengthened 69 percent in the last quarter of 2005 compared to the last quarter of 2004. Increased production, combined with stronger commodity prices quarter over quarter, resulted in a 125 percent or $2.3 million increase in revenue (excluding the impact of hedging) and a 178 percent or $0.9 million increase in cash flow. Net earnings for the fourth quarter of 2005 were $1.1 million compared to a net loss of $0.2 million in the fourth quarter of 2004.

Revenue

Revenue Summary

	Year ended December 31, 2005			Year ended December 31, 2004		
Revenue ($)	**Montana**	**Canada**	**Total**	Montana	Canada	Total
Natural Gas	**5,795,862**	**4,544,742**	**10,340,604**	705,980	3,538,436	4,244,416
Crude Oil	**–**	**1,558,189**	**1,558,189**	–	1,681,029	1,681,029
Crude Oil and Natural Gas Sales	**5,795,862**	**6,102,931**	**11,898,793**	705,980	5,219,465	5,925,445
Royalty Income	**–**	**455,723**	**455,723**	–	273,489	273,489
Net Hedging Gain	**–**	**152,590**	**152,590**	–	214,421	214,421
Total Revenue	**5,795,862**	**6,711,244**	**12,507,106**	705,980	5,707,375	6,413,355
Average Sales Price*						
Natural Gas ($/Mcf)	**8.88**	**8.73**	**8.81**	7.53	6.32	6.48
Crude Oil ($/Bbl)	**–**	**40.65**	**40.65**	–	34.80	34.80
Total Average Sales Price ($/BOE)	**53.27**	**49.07**	**50.95**	45.21	36.97	37.72

*Includes royalty income and royalty volumes.

Total revenue increased 95 percent to $12.5 million in 2005 from $6.4 million in 2004. Revenue for the year was positively impacted by increased production and strong commodity prices in 2005.

Natural gas revenue for 2005 was $10.3 million compared to $4.2 million in 2004, a 144 percent increase. Increases in natural gas revenue resulted from a 76 percent increase in natural gas production volumes and a 36 percent increase in price. Natural gas revenue, including net hedging gains, was 84 percent of total revenues compared to 70 percent in the prior year.

Crude oil and natural gas liquids revenue decreased 7 percent to $1.6 million from $1.7 million in 2004. This decrease is the result of a 20 percent decrease in oil and natural gas liquids volumes related to producing property sales and natural declines partially offset by a 17 percent increase in price.

Natural Gas Pricing

AltaCanada markets gas at a differential to the Alberta "AECO – Index price" which directly reflects changes in the market, transportation costs and foreign exchange rates. Both our Alberta and Montana volumes utilize this same "AECO – Index price".

Crude Oil Pricing

	2005	2004
WTI (US$/Bbl at Cushing, Oklahoma)	**56.55**	41.42
Average Exchange Rate ($)	**1.2117**	1.3015
WTI (CDN$/Bbl at Cushing, Oklahoma)	**68.52**	53.91
Less: Transportation and Quality Differential	**(27.87)**	(19.11)
AltaCanada Average Crude Oil Price (CDN$/Bbl)	**40.65**	34.80

AltaCanada's average oil price reflects the posted price less deductions for transportation and quality adjustments relative to the posted price. In 2005, total crude oil and natural gas liquids production was comprised of 95 percent medium heavy (Wildmere), 4 percent light and 1 percent natural gas liquids. The Wildmere crude oil price differential increased in 2005 resulting in a 17 percent increase in crude oil prices to $40.65 per barrel from $34.80 per barrel in 2004. All crude oil production is from AltaCanada's Canadian properties.

Commodity Price Risk Management

The Corporation uses derivative financial instruments to hedge its commodity price exposure. Financial instruments used for the year ended December 31, 2005 are:

Natural Gas Costless Collars - Unrealized at December 31, 2005:

Volume (GJ/day)	Volume (GJ)	Cap $/GJ	Floor $/GJ	Term	Unrealized Gain (Loss)
1,000	152,000	$13.35	$10.00	November 2005 to March 2006	40,033
1,000	152,000	$14.10	$12.00	November 2005 to March 2006	201,155
Total Unrealized Gain					$ 241,188

Natural Gas Costless Collars:- Realized in 2005

Volume (GJ/day)	Volume (GJ)	Cap $/GJ	Floor $/GJ	Term	Realized Gain (Loss)
1,000	92,000	$7.65	$6.50	August 2005 to October 2005	$ (143,908)
1,000	152,000	$14.10	$12.00	November 2005 to March 2006	55,310
1,000	151,000	$8.99	$8.00	November 2004 to March 2005	151,760
1,000	90,000	$7.45	$7.00	January 2005 to March 2005	63,826
Total Realized Gain					$ 126,988

The mark to market value of the hedges outstanding at December 31, 2005 is a financial derivative asset of $241,188. There are no natural gas or oil hedges in place at March 30, 2006.

Expenses

Royalties

Royalties include obligations to governments, freehold owners, and gross overriding royalties. AltaCanada's average royalty rate increased 1.78 percent to 22.85 percent compared to 21.07 percent in 2004. In Montana the royalty rate increased 2.77 percent due to the expiry of the Montana production tax incentive applicable for one year of production on wells drilled in 2004. In Canada royalties rates are consistent with the royalty rates realized in 2004.

	Year ended December 31, 2005			Year ended December 31, 2004		
	Montana	**Canada**	**Total**	Montana	Canada	Total
Royalties ($)						
Crown (Net of ARTC)	**–**	**785,260**	**785,260**	–	578,449	578,449
Freehold and Other	**1,432,663**	**501,539**	**1,934,202**	154,961	515,261	670,222
Total Royalties ($)	**1,432,663**	**1,286,799**	**2,719,462**	154,961	1,093,710	1,248,671
Average Royalty Rate (%)						
Crown (Net of ARTC)	**–**	**12.87**	**6.60**	–	11.08	9.76
Freehold and Other	**24.72**	**8.22**	**16.26**	21.95	9.87	11.31
Total Royalties (%)	**24.72**	**21.08**	**22.85**	21.95	20.95	21.07
Total Royalties ($/BOE)	**13.17**	**9.63**	**11.22**	9.85	7.36	7.60

Production Expenses

	Year ended December 31, 2005			Year ended December 31, 2004		
	Montana	**Canada**	**Total**	Montana	Canada	Total
Production & Transportation ($)	**1,015,271**	**1,286,483**	**2,301,754**	115,408	1,519,310	1,634,718
Less: Processing Income ($)	**–**	**(215,237)**	**(215,237)**	–	(279,410)	(279,410)
Net Production & Transportation ($)	**1,015,271**	**1,071,246**	**2,086,517**	115,408	1,239,900	1,355,308
Production & Transportation ($/BOE)	**9.33**	**9.62**	**9.49**	7.33	10.22	9.95
Less: Processing Income ($/BOE)	**–**	**(1.61)**	**(0.88)**	–	(1.88)	(1.70)
Net Production Expense ($/BOE)	**9.33**	**8.01**	**8.61**	7.33	8.34	8.25

In 2005, production and transportation expense (net of processing income) per BOE was $8.61 compared to $8.25 in 2004, a four percent increase. In Canada, production and transportation expense per BOE decreased four percent due to the sale of mature Canadian properties with relatively higher operating costs. On a BOE basis, Montana production and transportation expense increased 27 percent over prior year due to increased fuel gas costs for part of 2005. Processing income decreased 23 percent to $215,237 in 2005 from $279,410 in 2004 due to Canadian property sales.

Summary of Operating Netbacks

($/BOE)	Year ended December 31, 2005			Year ended December 31, 2004		
	Montana	**Canada**	**Total**	Montana	Canada	Total
Sales Price	**53.27**	**49.07**	**50.95**	45.21	36.97	37.72
Royalties (net ARTC)	**(13.17)**	**(9.63)**	**(11.22)**	(9.85)	(7.36)	(7.60)
Production Expenses	**(9.33)**	**(8.01)**	**(8.61)**	(7.33)	(8.34)	(8.25)
Operating Netbacks	**30.77**	**31.43**	**31.12**	28.03	21.27	21.87

General & Administrative

($)	2005			
	Gross	**Capitalized**	**Expensed**	**% Capitalized**
Personnel Costs	**1,232,442**	**672,502**	**559,940**	**55%**
Office Expenses	**489,174**	**98,063**	**391,111**	**20%**
Shareholder Information Costs	**182,290**	**–**	**182,290**	**–**
Professional Fees	**251,785**	**–**	**251,785**	**–**
Other	**146,212**	**41,913**	**104,299**	**29%**
Total	**2,301,903**	**812,478**	**1,489,425**	**35%**
$/BOE	**9.49**	**3.35**	**6.14**	

($)	2004			
	Gross	Capitalized	Expensed	% Capitalized
Personnel Costs	1,261,168	705,258	555,910	56%
Office Expenses	531,041	238,123	292,918	45%
Shareholder Information Costs	117,229	–	117,229	–
Professional Fees	155,730	–	155,730	–
Other	40,032	21,733	18,299	54%
Total	2,105,200	965,114	1,140,086	46%
$/BOE	12.81	5.87	6.94	

In 2005 general and administrative expense increased 31 percent to $1,489,425 in 2005 from $1,140,086 in 2004 but on a BOE basis, decreased 12 percent to $6.14 from $6.94. Gross general and administrative costs increased 9 percent to $2,301,903 in 2005 from $2,105,200 in 2004. Higher gross general and administrative costs in 2005 are the result of higher audit and tax preparation fees, increased Montana travel expenditures and higher shareholder information costs. Also increasing general and administrative costs was a settlement with Alberta FutureVest Corporation (AFVC) resulting in a $52,782 net charge to general and administrative expense in 2005.

The Corporation capitalizes general and administrative costs attributable to acquisition, exploration and development activities. In Canada, personnel costs of $216,688 (2004 - $345,600) and general overhead costs of $139,976 (2004 - $184,257) were capitalized. In Montana, personnel costs of $444,645 (2004 - $359,658) and general overhead costs of $11,169 (2004 - $75,599) were capitalized.

The Corporation's total capitalized portion of general and administrative costs has declined to 35 percent in 2005 from 46 percent in 2004. The decline in this rate is due to reduced capital activity in Canada and the commencement of production in Montana on October 1, 2004 after which time general and administrative costs related to non-capital activities were expensed.

As production increases from future drilling and tie-ins on the Corporation's lands in Montana, further decreases in general and administrative costs per unit are expected.

Stock Based Compensation

Stock Based Compensation expense increased 36 percent to $411,953 in 2005 from $303,113 in 2004. This increase is mainly due to an increase in the number and value of options granted in 2005, 2,000,000 at a weighted average exercise price of $0.61 compared to 560,000 at a weighted average exercise price of $0.59 in 2004.

Interest Expense and Financing Charges

($)	**2005**	2004
Interest on Bank Indebtedness	**280,457**	209,299
Financing Costs on Bridge Facility	**408,723**	–
Interest on 8% Convertible Debentures	**–**	38,597
Other Interest Expense	**146,872**	10,194
Total Interest	**836,052**	258,090
$/BOE	**3.45**	1.57
EBIT	**1,797,547**	(145,624)
Interest Expense	**836,052**	258,090
EBIT Interest Coverage	**2.15**	(0.56)
EBITDA	**5,676,108**	2,390,917
Interest Expense	**836,052**	258,090
EBITDA Interest Coverage	**6.79**	9.26

EBIT - earnings before interest expense, income taxes.
EBITDA - earnings before interest expense, income taxes, depletion, depreciation and accretion of asset retirement obligation.

Interest expense increased during 2005 to $836,052 from $258,090 in 2004. This increase was due to higher average indebtedness, higher interest rates and financing costs of $258,488 related to the bridge facility and new bank debt. Other interest is primarily an assessment of $162,253 related to Part XII.2 tax (interest) partially offset by interest income of $23,561. In 2004, AltaCanada's convertible debentures were fully redeemed, therefore no interest was charged in 2005.

Depletion, Depreciation & Accretion

($)	**Year ended December 31, 2005**			Year ended December 31, 2004		
	Montana	**Canada**	**Total**	**Montana**	**Canada**	**Total**
Depletion and Depreciation	**1,509,876**	**2,261,854**	**3,771,730**	270,848	2,195,972	2,466,820
Accretion of Asset Retirement Obligation	**16,912**	**89,919**	**106,831**	21,637	48,084	69,721
Total	**1,526,788**	**2,351,773**	**3,878,561**	292,485	2,244,056	2,536,541
$/BOE	**14.03**	**17.59**	**16.00**	18.58	15.10	15.44

Depletion, depreciation and accretion per BOE in 2005 increased to $16.00 per BOE from $15.44 per BOE in 2004. The 2005 depletion and depreciation expense increased 53 percent to $3.8 million compared to $2.5 million in 2004 due to a 48 percent increase in production and a slightly higher depletion rate. Due to property dispositions, costs related to unproved properties, valued at cost, in Canada decreased to $794,000 in 2005 from $1,550,000. These costs have been excluded from costs subject to depletion.

Depletion on Montana properties was initially recorded October 1, 2004 with the commencement of production. In 2005, costs related to unproved properties, valued at cost, in Montana are $6.3 million compared to $5.6 million in 2004. These costs as well as inventory of $543,340 at December 31, 2005 have been excluded from costs subject to depletion.

To focus the Corporation's efforts in Montana, non-core Canadian assets have been rationalized, commencing in July 2002. This continued with dispositions in 2003, 2004, and 2005. We continue to aggressively exploit existing development resources in Montana and on our remaining Canadian properties. With a sustained drilling program and expanded reserve additions, the Corporation expects to reduce depletion in 2006.

Asset Retirement Obligation

At December 31, 2005 the Corporation's asset retirement obligation is $1.2 million. In Canada, dispositions in 2005 reduced the asset retirement obligation "ARO" by $526,898. This reduction was partially offset by a revision to estimate of $207,287, and smaller increases related to new drilling and accretion expense. In Montana, increases to the asset retirement obligation were due to new drilling and accretion expense. The ARO assumptions are reviewed each quarter and revised as new information is available. Any changes to the ARO estimate are recognized prospectively. Reductions in the asset retirement obligation are an additional benefit of property dispositions.

($/BOE)	Montana	Canada	Total
Asset Retirement Obligation, December 31, 2003	**43,453**	**593,853**	**637,306**
Liabilities Incurred	**228,551**	**84,108**	**312,659**
Disposals	**–**	**(211,706)**	**(211,706)**
Accretion Expense	**21,637**	**48,084**	**69,721**
Revision to Estimate	**(118,909)**	**524,974**	**406,065**
Asset Retirement Obligation, December 31, 2004	**174,732**	**1,039,313**	**1,214,045**
Liabilities Incurred	**129,945**	**69,223**	**199,168**
Disposals	**–**	**(526,898)**	**(526,898)**
Accretion Expense	**16,912**	**89,919**	**106,831**
Revision to Estimate	**–**	**207,287**	**207,287**
Asset Retirement Obligation, December 31, 2005	**321,589**	**878,844**	**1,200,433**

Taxes

The Corporation has recorded a current tax expense of $94,627 for 2005 compared to a current tax expense of $54,037 in 2004 and a future tax recovery of $202,890 in 2005 compared to a future tax recovery of $14,325 in 2004. In 2005 and 2004, Alberta Selecta Corporation (a 100% owned subsidiary) was currently taxable. The Corporation has tax deductions available to reduce future taxable income as set out in note 8 to the Consolidated Financial Statements.

Net Earnings Analysis

In 2005 the Corporation realized earnings per BOE of $4.41 compared to net loss per BOE of $2.70 in 2004. This increase was primarily due to increased commodity prices offset by increases in royalty expense and interest and financing charges.

($/BOE)	**2005**	2004
Crude Oil and Natural Gas Revenue	**50.95**	37.72
Realized Hedging Gain (Loss)	**0.52**	(0.01)
Royalty Expense	**(11.22)**	(7.60)
Production and Transportation Expense	**(8.61)**	(8.24)
General and Administrative	**(6.14)**	(6.94)
Financing Charges	**(3.45)**	(1.50)
Realized Foreign Exchange Gain (Loss)	**(0.12)**	0.15
Current Income Tax Expense	**(0.39)**	(0.33)
Cash Flow from Operations	**21.55**	13.25
Discount Accretion on 8% Debentures	**–**	(0.07)
Stock Based Compensation	**(1.70)**	(1.84)
Unrealized Hedging Gain (Loss)	**0.11**	1.31
Depletion, Depreciation and Accretion	**(16.00)**	(15.44)
Unrealized Foreign Exchange Gain (Loss)	**(0.08)**	–
Bad Debt Expense	**(0.31)**	–
Future Income Taxes Recovery (Expense)	**0.84**	0.09
Net Earnings (Loss)	**4.41**	(2.70)

Common Share Information

	2005	2004
Outstanding Shares		
Weighted Average Outstanding Shares		
Basic	**59,957,912**	54,240,403
Diluted	**60,014,715**	56,417,424
Basic Outstanding Shares December 31	**60,017,844**	59,488,251
Per Share Information ($)		
Net Earnings (Loss)	**1,069,758**	(443,426)
Per Share: Basic	**0.02**	(0.01)
Diluted	**0.02**	(0.01)
Cash Flow from Operations	**5,226,412**	2,177,314
Per Share: Basic	**0.09**	0.04
Diluted	**0.09**	0.04

Common shares were issued in 2005 as set out in note 6 to the Consolidated Financial Statements.

Capital Expenditures

Capital expenditures summary

($)	**2005**	2004	2003
Land and Lease	**1,101,310**	1,325,373	6,056,910
Geological and Geophysical Costs	**455,506**	1,069,921	940,184
Drilling and Completions	**8,621,090**	7,978,503	6,146,267
Facilities	**1,371,690**	2,276,890	697,330
Inventory	**543,340**	890,938	–
Corporate Assets	**8,070**	4,867	96,735
Capital Expenditures before Dispositions	**12,101,006**	13,546,492	13,937,426
Dispositions	**(2,718,174)**	(3,561,923)	(385,085)
Net Capital Expenditures	**9,382,832**	9,984,569	13,552,341

In 2005, AltaCanada continued its focus on Montana while continuing to rationalize mature Canadian assets. Capital expenditures in 2005 decreased slightly to $12.1 million from $13.5 million in 2004.

In 2005, AltaCanada spent $8.6 million or 71 percent of capital expenditures drilling 34 wells in Montana for $7.1 million and $1.5 million drilling 4 wells in Canada. This is a remarkably high percentage of total capital directed to drilling that is expected to be repeated in future years as the Corporation focuses on adding production and reserves through the drill bit. Facilities expenditures were $1.4 million, seismic and gravity expenditures comprised $0.5 million and $1.1 million was spent on acquiring lands. Inventory of $0.5 million relates primarily to line pipe, casing and other wellhead equipment carried at cost to be used in the 2006 Montana capital program. Canadian assets continued to be rationalized with $2.7 million of aggregated dispositions during the year.

Segmented Capital Expenditures Summary

2005 ($)	**CANADA**	**MONTANA**	**TOTAL**
Land and Lease	**65,644**	**1,035,666**	**1,101,310**
Geological and Geophysical Costs	**29,838**	**425,668**	**455,306**
Drilling and Completions	**1,487,832**	**7,133,258**	**8,621,090**
Facilities	**331,466**	**1,040,224**	**1,371,690**
Inventory	**–**	**543,340**	**543,340**
Corporate Assets	**8,070**	**–**	**8,070**
Capital Expenditures before Dispositions	**1,922,850**	**10,178,156**	**12,101,006**
Property Dispositions	**(2,718,174)**	**–**	**(2,718,174)**
Total Capital Expenditures	**(795,324)**	**10,178,156**	**9,382,832**

2004 ($)	CANADA	MONTANA	TOTAL
Land and Lease	381,459	943,914	1,325,373
Geological and Geophysical Costs	126,847	943,074	1,069,921
Drilling and Completions	1,798,837	6,179,666	7,978,503
Facilities	600,211	1,676,679	2,276,890
Inventory	–	890,938	890,938
Corporate Assets	4,867	–	4,867
Capital Expenditures before Dispositions	2,912,221	10,634,271	13,546,492
Property Dispositions	(3,561,923)	–	(3,561,923)
Total Capital Expenditures	(649,702)	10,634,271	9,984,569

Drilling Results

	2005		2004		2003	
	Gross	**Net**	Gross	Net	Gross	Net
Natural Gas	**28.0**	**26.0**	39.0	22.4	15.0	8.2
Crude Oil	**0.0**	**0.0**	5.0	0.6	1.0	0.0
Dry and Abandoned *	**10.0**	**8.0**	12.0	5.5	10.0	5.5
Total	**38.0**	**34.0**	56.0	28.5	26.0	13.7
Success Rate (%)	**73.7**	**76.5**	78.6	80.7	61.5	60.0

*Includes suspended wells.

Segmented Drilling Results

2005	**CANADA**		**MONTANA**		**TOTAL**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Natural Gas	**2.0**	**1.0**	**26.0**	**25.0**	**28.0**	**26.0**
Crude Oil	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Dry and Abandoned *	**2.0**	**0.7**	**8.0**	**7.3**	**10.0**	**8.0**
Total	**4.0**	**1.7**	**34.0**	**32.3**	**38.0**	**34.0**
Success Rate (%)	**50.0**	**58.8**	**76.5**	**77.4**	**73.7**	**76.5**

2004	CANADA		MONTANA		TOTAL	
	Gross	Net	Gross	Net	Gross	Net
Natural Gas	12.0	1.2	27.0	21.2	39.0	22.4
Crude Oil	5.0	0.6	0.0	0.0	5.0	0.6
Dry and Abandoned *	1.0	0.3	11.0	5.2	12.0	5.5
Total	18.0	2.1	38.0	26.4	56.0	28.5
Success Rate (%)	94.4	85.7	71.1	80.0	78.6	80.7

*Includes suspended wells.

In 2005 AltaCanada participated in 34 wells in Montana and 4 wells in Canada. Average working interest participation increased to 89.5 percent in 2005 from 50.9 percent in 2004. The net success rate was down slightly to 76.5 percent in 2005 from 80.7 percent in 2004.

Undeveloped Land Holdings

(Acres)	**2005**		2004	
	Gross	**Net**	Gross	Net
Canada	**28,547**	**9,871**	77,516	19,271
Montana	**198,224**	**182,084**	169,982	169,982
Total	**226,771**	**191,956**	247,498	189,253

AltaCanada's undeveloped land portfolio is located in east central Alberta and Montana. In Canada, total undeveloped net acres decreased 49 percent in 2005 to 9,871 acres from 19,271 net acres in 2004 due to non-core property dispositions offset by the purchase of 54 net acres for an average cost of $293.93 per acre. AltaCanada's average working interest in undeveloped acreage in Canada increased to 35 percent in 2005 from 25 percent in 2004, as the Corporation focused on our core Canadian prospects. In Montana, total undeveloped acres increased 7 percent to 182,084 net acres from 169,982 net acres in 2004. This increase is due to land purchases of 34,901 net acres at an average cost of $23.00 US per acre offset by the success of the 2005 Montana drilling program which converted undeveloped land to the developed category.

Recent land sales in Montana have ranged between $2.00 and $265.00 per net acre. An independent appraisal of our undeveloped Montana land was provided by Heringer Herco, LLC of Billings, Montana, who assessed it at a value of US $10.5 million (CDN $12.3 million) compared to US $11.1 million (CDN $13.5 million) in 2004.

The Corporation's strategy is to continue to focus upon exploration and development of its Montana land base. AltaCanada will continue to pursue low risk prospects in Canada.

Reserves

In 2005, 2004 and 2003 reserves for both Montana and Alberta are expressed in accordance with the reserves definitions under NI 51 -101.

The crude oil and natural gas reserves of the Corporation were evaluated effective December 31, 2005 by GLJ Petroleum Consultants Ltd. (GLJ), independent petroleum engineering consultants.

The evaluation is in compliance with National Instrument 51-101 entitled "Standards of Disclosure for Oil and Gas Activities" (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGEH). Additional detail is contained in the Annual Information Form available on Sedar.

GLJ performs a bottoms-up analysis where individual properties are evaluated. Individual evaluators review historical production, well activity, ownership issues and development plans to determine the evaluation approach. Reserves are typically assigned based on material balance analysis, decline analysis, volumetric calculations or by a combination of any of these methods. AltaCanada input is provided early in the process. Where possible, performance based reserves assignments are made. For significant properties with performance based reserves assignments, the volumetric recovery is also considered to address the reasonableness of the assignment. Development opportunities are also considered. A geological analysis or audit is generally

conducted where the reserve assignment is volumetrically based. Accounting statements are reviewed as a check on interests, product pricing, operating costs and royalty burdens.

At year-end 2005, AltaCanada's proved plus probable natural gas reserves increased 56 percent to 20.028 BCF from 12.857 BCF in 2004. Proved plus probable crude oil and natural gas liquids reserves decreased 20 percent to 346,000 Bbls from 433,000 Bbls in 2004. The changes in reserves reflect a combination of drilling results, production and asset sales. The Corporation's reserve life index is 9.4 years for proved and 16.3 years for proved plus probable natural gas reserves; and 6.7 years for proved and 9.0 years for proved plus probable crude oil and natural gas liquids reserves.

Under COGEH and NI 51-101 guidelines, probable reserves are those lower certainty reserves which, when added to the higher certainty proved reserves, results in a proved plus probable reserve estimate which is representative of the evaluator's "best estimate" for a specific entity. With respect to comparison to previous practice and regulations, current probable reserves have been adjusted for risk.

AltaCanada conducts its own due diligence in addition to the reserve estimation prepared by GLJ. Nevertheless, it is important to note that these estimates are subject to revisions, either positive or negative, as additional information becomes available.

Reserves Summary

	2005			2004			2003		
	Oil & NGLs	**Gas**	**Total**	Oil & NGLs	Gas	Total	Oil & NGLs	Gas	Total
	MBbls	**MMcf**	**MBOE**	MBbls	MMcf	MBOE	MBbls	MMcf	MBOE
Canada									
Proved Producing	**258**	**2,053**	**601**	327	2,265	704	397	2,941	887
Proved	**258**	**2,570**	**687**	334	3,345	891	403	4,340	1,126
Proved plus Probable	**346**	**3,513**	**932**	433	4,489	1,181	497	5,766	1,458
Montana									
Proved Producing	**–**	**3,479**	**580**	–	3,377	563	–	–	–
Proved	**–**	**8,931**	**1,488**	–	5,340	890	–	–	–
Proved plus Probable	**–**	**16,515**	**2,752**	–	8,368	1,395	–	–	–
TOTAL									
Proved Producing	**258**	**5,532**	**1,181**	327	5,642	1,267	397	2,941	887
Proved	**258**	**11,501**	**2,175**	334	8,685	1,781	403	4,340	1,126
Proved plus Probable	**346**	**20,028**	**3,684**	433	12,857	2,576	497	5,766	1,458

Present Value Of Reserves

($ millions, before Income taxes)		**2005**			2004			2003	
Discount Factor	**0%**	**10%**	**15%**	0%	10%	15%	0%	10%	15%
Canada									
Proved	**15.27**	**11.25**	**10.08**	15.95	11.74	10.45	15.50	11.95	10.80
Total Proved plus Probable	**19.97**	**13.88**	**12.19**	21.37	14.86	12.98	19.77	14.49	12.89
Montana									
Proved	**31.79**	**22.58**	**19.98**	13.42	7.94	6.56	–	–	–
Total Proved plus Probable	**56.52**	**36.37**	**31.31**	21.43	11.37	9.00	–	–	–
TOTAL									
Proved	**47.06**	**33.83**	**30.06**	29.37	19.68	17.01	15.50	11.95	10.80
Total Proved plus Probable	**76.49**	**50.25**	**43.50**	42.80	26.23	21.98	19.77	14.49	12.89

For 2005, the discounted net present value of AltaCanada's reserves was estimated using average 2006 prices of $10.23 per Mcf of natural gas and $40.33 per Bbl of oil and natural gas liquids and adjusted in future years pursuant to GLJ's January 2006 price forecast. The net present value of proved plus probable reserves, discounted at 10 percent, has increased 92 percent to $50.3 million up from $26.2 million in 2004.

All estimated future cash flows are stated prior to provisions for income taxes, indirect costs and asset retirement costs but after deduction of operating costs, royalties and future capital expenditures.

Reserves Reconciliation

		Proved			Proved Plus Probable	
MBOE	Montana	Canada	Total	Montana	Canada	Total
December 31, 2003	–	1,126	1,126	–	1,458	1,458
Drilling Additions	905	79	984	1,410	107	1,517
Revisions	–	(11)	(11)	–	(28)	(28)
Acquisitions	–	–	–	–	–	–
Dispositions	–	(154)	(154)	–	(207)	(207)
2004 Net Reserve Additions	905	(86)	819	1,410	(128)	1,282
Production	(16)	(148)	(164)	(16)	(148)	(164)
December 31, 2004	889	892	1,781	1,395	1,181	2,576
Drilling Additions	694	51	745	1,330	78	1,408
Revisions	13	(19)	(6)	137	(29)	108
Acquisitions	-	-	-	-	-	-
Dispositions	-	(102)	(102)	-	(165)	(165)
2005 Net Reserve Additions	707	(70)	637	1,467	(116)	1,351
Production	(109)	(134)	(243)	(109)	(134)	(243)
December 31, 2005	1,487	688	2,175	2,753	931	3,684

Proved Plus Probable totals have increased 2.5 times in two years.

Reserves Life Index

	2005	2004	2003
Crude Oil and NGL			
Production (Bbls)	**38,244**	48,312	64,398
Proved Reserves (Bbls)	**258,000**	334,000	403,000
Proved Reserve Life Index (years)	**6.7**	6.9	6.3
Proved Plus Probable Reserves (Bbls)	**346,000**	433,000	496,800
Proved Plus Probable Reserve Life Index (years)	**9.0**	9.0	7.7
Natural Gas			
Production (Mcf)	**1,225,355**	696,864	870,277
Proved Reserves (Mcf)	**11,501,000**	8,685,000	4,340,000
Proved Reserves Life Index (years)	**9.4**	12.5	5.0
Proved Plus Probable Reserves (Mcf)	**20,028,000**	12,857,000	5,766,000
Proved Plus Probable Reserve Life Index (years)	**16.3**	18.4	6.6

Reserves Replacement

	Cumulative 2003-2005	2005	2004	2003
Production (BOE)	**616,304**	**242,470**	164,334	209,500
Net Proved:				
Reserves Additions (BOE)	**1,585,000**	**637,000**	819,000	129,000
Net Proved Replacement Ratio	**2.57**	**2.63**	4.98	0.62
Net Proved Plus Probable:				
Reserves Additions (BOE)	**2,728,000**	**1,351,000**	1,282,000	95,000
Net Proved Plus Probable Replacement Ratio	**4.43**	**5.57**	7.80	0.45

Net Future Expenditures

The reserves report details future capital requirements to maintain proved producing reserves and to bring proved non-producing and probable reserves on production. Estimated future capital requirements in Canadian dollars are estimated by GLJ to be $6,064,000 (Montana $5,255,000, Canada $809,000) for the proved non-producing reserves and $7,022,000 (Montana $6,118,000, Canada $904,000) for the probable reserves.

Consolidated Finding And Development Costs

	Cumulative 2003-2005	2005	2004	2003
Capital Expenditures before Dispositions ($)	**30,465,339**	**11,557,666**	12,655,554	6,252,119
Net Acquisitions (dispositions) ($)	**(6,665,182)**	**(2,718,174)**	(3,561,923)	(385,085)
Total Capital Expenditures ($)*	**23,800,157**	**8,839,492**	9,093,631	5,867,034
Proved				
Net Reserves Additions (BOE)	**1,585,000**	**637,000**	819,000	129,000
Finding and Development Costs ($/BOE)	**15.02**	**13.88**	11.10	45.48
Proved Plus Probable				
Net Reserves Additions (BOE)	**2,728,000**	**1,351,000**	1,282,000	95,000
Finding and Development Costs ($/BOE)	**8.72**	**6.54**	7.09	61.76

* Excludes December 31, 2005 inventory of $543,340 and December 31, 2004 inventory of $890,938.

Full cycle exploration is generally a three year process. The cumulative three year finding and development costs, 2003 to 2005 is $8.72 per BOE using proved plus probable net reserves additions.

In 2005, booked reserves reflect the impact of drilling results, production, and the rationalization of Canadian assets.

In 2005, on a proved plus probable basis, finding and development costs of $6.54 per BOE were lower than the prior year. On a proved basis, finding and development costs of $13.88 per BOE was higher than 2004. Higher proved finding and development costs are the result of Montana capital expenditures recorded late in 2005 for which proved reserves were not recognized. The calculation of finding and development costs can be skewed by differences in the timing of expenditures and the phase of the exploration cycle, therefore, three year cumulative finding and development costs are presented above.

Recycle Ratio

	2005	2004
Operating Netback ($/BOE)	**31.12**	21.87
Proved Finding and Development Costs ($/BOE)	**13.88**	11.10
Proved Reinvestment Efficiency Ratio	**2.2**	2.0
Proved Plus Probable Finding and Development Costs ($/BOE)	**6.54**	7.09
Proved Plus Probable Reinvestment Efficiency Ratio	**4.8**	3.1

The recycle ratio evaluates the effectiveness of a Corporation's reinvestment program. It is one measure of the Corporation's efficiency replacing reserves. This is determined by dividing the operating netback per BOE by the finding and development cost per BOE.

Financial Resources

At December 31, 2005 total debt, as set out in the table below, was $10.3 million compared to total net debt at December 31, 2004 of $6.2 million. At the end of 2005, total debt consisted of $6.6 million in bank indebtedness and a $3.7 million working capital deficiency. AltaCanada funded its 2005 capital program of $12.1 million through a combination of a $4.1 million increase to bank indebtedness and working capital deficiency, internally generated cash flows of $5.2 million and the divestiture of non core properties totaling $2.7 million. The Corporation's bank indebtedness is described in note 4 to the Consolidated Financial Statements.

The Corporation's planned capital expenditure program for the first half of 2006, estimated to be approximately $6.4 million, will be funded with corporate cash flow and increased bank indebtedness. Negotiations with the Bank to increase our line of credit to $10.0 million are underway. Incremental capital expenditures for the second half of 2006 will be funded solely from cash flow from operations. An equity financing in the second half of 2006 may be considered if markets are favorable.

Key Debt Ratios

($)	**2005**	2004
Bank Indebtedness	**6,587,940**	3,596,317
Working Capital Deficiency	**3,750,188**	2,655,817
Total Debt	**10,338,128**	6,252,134
Cash Flow from Operations	**5,226,412**	2,177,314
Years Cash Flow to Repay Total Debt		
Trailing	**1.98**	2.87
Forward*	**0.89**	1.20
Asset Coverage Ratio		
Risked Proved plus Probable Reserves (discounted at 10%)	**50,250,000**	26,230,000
Total Debt	**10,338,128**	6,252,134
Asset Coverage Ratio	**4.86**	4.20
Total Debt/Equity Ratio		
Total Debt	**10,338,128**	6,252,134
Shareholders' Equity	**25,438,738**	23,817,571
Total Debt/Equity	**0.41**	0.26
Total Debt/EBITDA		
Total Debt	**10,338,128**	6,252,134
EBITDA	**5,676,108**	2,390,917
Total Debt/EBITDA	**1.82**	2.61

* Assumes 2006 cash flow of $11.6 million (assumes average gas price of CDN $6.50/Mcf and average daily production of 1,350 BOE/d).

2006 Forecast

Early first quarter 2006 drilling success (7 wells) in Montana and tie-ins combined with the addition of new compression facilities has increased Montana production to 5.8 MMcf/d in March 2006. Additional 2006 drilling should further increase production and reserves and at an estimated natural gas price of $6.50/Mcf is expected to result in cash flow of approximately $11.6 million which will more than double our 2005 cash flow.

The Corporation's significant gas production makes its cash flow very sensitive to the price of gas. For every $1.00/Mcf change in the price of gas estimated 2006 cash flow will change by approximately $2.0 million.

Capitalization (Non-GAAP disclosure)

AltaCanada's total capitalization increased 36 percent in 2005 to $65.7 million from $48.3 million in 2004. In 2005, the market value of common shares is 79 percent of total capitalization. Total debt represents 16 percent of total capitalization.

($ except per share amounts)	**2005**	**%**	2004	%
Common Shares Outstanding	**60,017,844**		59,488,251	
Share Price - ($) December 31 on TSX	**0.87**		0.65	
Market Capitalization	**52,215,524**	**79**	38,667,363	80
Bank Indebtedness	**6,587,940**	**10**	3,596,317	8
Other Working Capital Deficiency	**3,750,188**	**6**	2,655,817	5
Total Debt	**10,388,128**	**16**	6,252,134	13
Asset Retirement Obligation	**1,200,433**	**2**	1,214,045	3
Future Income Taxes	**1,961,261**	**3**	2,164,151	4
Total Capitalization	**65,715,346**	**100**	48,297,693	100
Total Debt to Capitalization (%)	**15.81**		12.94	

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Related Parties

With the resignation of Josef Hodel, a director and officer of the Corporation, February 4, 2005, Alberta FutureVest Corporation (AFVC) ceased to be a related party. Transactions with AFVC are disclosed in note 9 to the consolidated financial statements. Currently, the Corporation does not engage in any material or unusual related party transactions and does not anticipate any such transactions in the future.

Accounting Policy Changes

Financial Instruments — Recognition and Measurement, CICA Handbook Section 3855

Section 3855 prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet and at what amount – sometimes using fair value; other times using cost-based measures. It also specifies how financial instrument gains and losses are to be presented.

Section 3855 applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. Transitional provisions for this Section are complex and vary based on the type of financial instrument under consideration. The expected effect on the Corporation's financial statements cannot be reasonably determined at this time.

Management's Report

The accompanying consolidated financial statements of AltaCanada Energy Corp. were prepared by and are the responsibility of management. They have been prepared in conformity with Canadian generally accepted accounting principles. The financial information in the annual report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains systems of internal accounting control designed to provide reasonable assurance that all transactions are properly recorded in the Corporation's book of accounts, that procedures and policies are adhered to and that assets are safeguarded from unauthorized use.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, has been engaged, as approved by the shareholders at the last annual meeting, to examine the financial statements in accordance with Canadian generally accepted auditing standards and provide an independent professional opinion.

The Audit Committee of AltaCanada Energy Corp., comprised of a majority of independent directors, has met with representatives of PricewaterhouseCoopers LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. On the recommendation of the Audit Committee, the financial statements have been approved by the Board of Directors.

Charles V. Selby
Chairman, Chief Financial Officer, and Director
Calgary, Canada, March 30, 2006

Donald E. Foulkes
President, Chief Executive Officer, and Director

Auditors' Report

To the shareholders of AltaCanada Energy Corp.,

We have audited the consolidated balance sheets of AltaCanada Energy Corp., as at December 31, 2005 and 2004 and the consolidated statements of earnings and retained earnings and cash flow for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the consolidated financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatements. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion these consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Corporation as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Canada, March 30, 2006

Consolidated Balance Sheet

As at December 31		2005		2004
ASSETS				
Current Assets				
Cash	$	**196,672**	$	42,860
Accounts Receivable		**3,843,076**		3,204,558
Due from Related Parties (note 9)		**–**		6,955
Prepaid Expenses		**792,143**		424,210
Financial Derivatives Asset (note 10)		**241,188**		215,586
		5,073,079		3,894,169
Property, Plant and Equipment (note 2)		**38,938,560**		33,447,901
	$	**44,011,639**	$	37,342,070
LIABILITIES				
Current Liabilities				
Accounts Payable and Accrued Liabilities	$	**8,725,259**	$	6,488,809
Income Taxes Payable		**98,008**		61,177
Bank and Other Indebtedness (note 4)		**6,587,940**		3,596,317
		15,411,207		10,146,303
Asset Retirement Obligations (note 3)		**1,200,433**		1,214,045
Future Income Taxes (note 8)		**1,961,261**		2,164,151
SHAREHOLDERS' EQUITY				
Capital Stock (note 6)		**23,074,037**		22,934,581
Contributed Surplus (note 7)		**1,281,163**		869,210
Retained Earnings		**1,083,538**		13,780
		25,438,738		23,817,571
	$	**44,011,639**	$	37,342,070

Commitments (note 11)

Approved by the Board of Directors

Frank J.D. Sayer
Director

Michael J. Hibberd
Director

See accompanying notes to consolidated financial statements

Consolidated Statement of Earnings & Retained Earnings

For the Years Ended December 31		2005		2004
Revenue				
Crude Oil and Natural Gas Sales	$	**11,898,793**	$	5,925,445
Realized Hedging Gain (Loss) (note 10)		**126,988**		(1,165)
Unrealized Hedging Gain (note 10)		**25,602**		215,586
Royalty Income		**455,723**		273,489
Total Revenue		**12,507,106**		6,413,355
Royalties - Net of ARTC		**(2,719,462)**		(1,248,671)
		9,787,644		5,164,684
Expenses				
Production		**1,776,956**		1,123,183
General and Administrative		**1,489,425**		1,140,086
Transportation		**309,561**		232,125
Interest		**836,052**		258,090
Stock Based Compensation (note 7)		**411,953**		303,113
Accretion of Asset Retirement Obligation (note 3)		**106,831**		69,721
Bad Debt Expense		**76,167**		–
Foreign Exchange Loss (Gain)		**47,474**		(24,740)
Depletion and Depreciation		**3,771,730**		2,466,820
		8,826,149		5,568,398
Earnings (Loss) Before Income Taxes		**961,495**		(403,714)
Income Taxes (note 8)				
Current		**94,627**		54,037
Future		**(202,890)**		(14,325)
		(108,263)		39,712
Net Earnings (Loss)		**1,069,758**		(443,426)
Retained Earnings, Beginning of Year		**13,780**		457,206
Retained Earnings, End of Year	$	**1,083,538**	$	13,780
Earnings (Loss) per Common Share				
Basic	$	**0.02**	$	(0.01)
Diluted	$	**0.02**	$	(0.01)
Weighted Average Number of Common Shares Outstanding				
Basic		**59,957,912**		54,240,403
Diluted		**60,014,715**		56,417,424

See accompanying notes to consolidated financial statements

Consolidated Statement of Cash Flow

For the Years Ended December 31		**2005**		2004
CASH PROVIDED BY:				
Operating Activities				
Net Earnings (Loss)	$	**1,069,758**	$	(443,426)
Items Not Affecting Cash				
Depletion and Depreciation		**3,771,730**		2,466,820
Accretion of Asset Retirement Obligations		**106,831**		69,721
Stock Based Compensation		**411,953**		303,113
Unrealized Hedging Gain (note 10)		**(25,602)**		(215,586)
Unrealized Foreign Exchange Loss (Gain)		**18,465**		–
Bad Debt Expense		**76,167**		–
Accretion of Discount on Convertible Debentures		**–**		10,997
Future Income Tax (Recovery)		**(202,890)**		(14,325)
Cash Flow from Operations		**5,226,412**		2,177,314
Change in Non-Cash Working Capital		**550,605**		(17,205)
		5,777,017		2,160,109
Financing Activities				
Increase in Bank Indebtedness		**2,991,623**		639,697
Issue of Share Capital, Net of Share Issue Costs		**139,456**		4,054,820
Redemption of Convertible Debentures		**–**		(4,779)
Change in Non-Cash Working Capital		**–**		–
		3,131,079		4,689,738
Investing Activities				
Additions to Property		**(12,101,006)**		(13,546,492)
Dispositions of Property		**2,718,174**		3,561,923
Change in Non-Cash Working Capital		**628,548**		3,113,908
		(8,754,284)		(6,870,661)
Increase (Decrease) in cash		**153,812**		(20,814)
Cash, Beginning of Year		**42,860**		63,674
Cash, End of Year	$	**196,672**	$	42,860
Supplemental Cash Flow Information				
Cash Income Taxes Paid	$	**57,796**	$	13,883
Net Cash Interest Paid	$	**467,096**	$	248,690

See accompanying notes to consolidated financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2005 AND 2004

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

AltaCanada Energy Corp. (the "Corporation or AltaCanada") operates in the oil and gas industry in Alberta and Montana. AltaCanada was incorporated under the Business Corporations Act (Alberta) on November 12, 1997.

The Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the revenues and expenses during the reporting period. Actual results can differ from these estimates.

In particular, the amounts recorded for depletion, depreciation and amortization of the petroleum and natural gas properties and for asset retirement obligation are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

Certain comparative figures have been reclassified to conform with current year presentation.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of AltaCanada Energy Corp. (ANG), and its wholly owned subsidiaries Alberta Selecta Corporation (ASC), ANG Holding Corp., ANG Holding (US) Corp., Montana Land and Exploration, Inc. (ML&E), and AltaCanada Energy Partnership (ACEP) which was formed June 1, 2003 by ANG and ASC. The year end for the Corporation and its subsidiaries is December 31 with the exception of AltaCanada Energy Partnership which has a January 31 year end.

Property, Plant and Equipment

The Corporation follows the full cost method of accounting for its petroleum and natural gas operations, whereby all costs of exploration for and development of petroleum and natural gas operations are capitalized on a country by country basis. Costs include lease acquisitions, geological and geophysical, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, lease and rental equipment and overhead directly related to exploration and development activities. Proceeds from the sale of properties are applied against capitalized costs, without any gain or loss being recognized, unless such sale would significantly alter the rate of depletion.

The Corporation performs a ceiling test calculation under a two part process. Part I, the recognition of impairment, is determined by comparing the carrying value of property, plant and equipment with the sum of the undiscounted cash flows expected to result from the production of the Corporation's proved reserves. Cash flows are calculated based on management's best estimate of future prices. If impairment exists, Part II calculates the magnitude of the impairment

by comparing the carrying value of the property, plant and equipment to the fair value of proved and probable reserves. Fair value is estimated using accepted present value techniques, which incorporate risk and other uncertainties as well as the future value of reserves when determining expected cash flows. A risk free interest rate is used to determine the net present value of future cash flows. Any excess carrying value above the net present value of future cash flows would be recorded as impairment and charged as additional depletion expense in the statement of earnings.

Asset Retirement Obligations

The Corporation recognizes the estimated fair value of an asset retirement obligation (ARO) in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability with a corresponding increase in the carrying amount of the related asset. ARO is initially measured at fair value and subsequently adjusted for the accretion of discount and any changes to the underlying cash flows. The capitalized amount is depleted on a unit-of-production basis over the life of the proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost result in an increase or decrease to ARO.

Depreciation and Depletion

Under full cost accounting, oil and gas properties are depleted using the unit-of-production method based upon estimated proved petroleum and natural gas reserves determined by independent petroleum engineers. Costs of significant unproved properties, net of impairments, are excluded from the depletion calculation. These properties are assessed annually to ascertain whether impairment has occurred. Other plant and equipment costs are depreciated using the declining balance basis based on the estimated useful lives of the assets, with rates ranging from 20 to 30 percent. Unproved property costs and major projects that are under construction are not depreciated or depleted.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, demand deposits, and investments in highly liquid money market instruments which are convertible to known amounts of cash in less than three months.

Joint Operations

Substantially all of the Corporation's petroleum and natural gas operations are conducted jointly with others. These financial statements reflect only the Corporation's proportionate interest in such activities.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes from the Corporation to its customer.

Income Taxes

Income taxes are recorded using the liability method of accounting. Applying this method, future income taxes are recognized using applicable enacted, or substantively enacted, income tax rates for future income tax consequences attributable to differences between the financial statement carrying values of assets and liabilities and their respective income tax bases. The effect of a change in tax rates on future income taxes and liabilities is included in income in the period that includes the enactment date. Future Income tax assets are evaluated and if realization is considered "more likely than not", no valuation allowance is provided.

Financial Instruments

The Corporation's financial instruments are comprised of cash, accounts receivable, accounts payable and accrued liabilities and bank indebtedness. The carrying amounts of these financial instruments approximate their estimated market values. From time to time, the Corporation may use derivative financial instruments to manage exposure to fluctuations in commodity prices, foreign currency exchange rates and interest rates. All transactions of this nature entered into by the Corporation are related to an underlying financial position to future petroleum and natural gas production. The Corporation does not use derivative financial instruments for speculative trading purposes.

The Corporation may enter into derivative contracts to manage its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. Any derivative contracts, which qualify for hedge accounting, are recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transactions are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

For transactions that do not qualify for hedge accounting, the Corporation applies the fair value method of accounting by recording an asset or liability on the balance sheet and recognizing changes in the fair value of the instruments in the statement of earnings.

Per Share Amounts

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period. Diluted per share amounts are calculated using the treasury stock method which assumes that any proceeds obtained on exercise of share options or warrants would be used to purchase common shares at the average market price during the period.

Stock Based Compensation

The Corporation recognizes obligations related to stock based compensation. An option-pricing model is used to determine the fair value of each option granted and the amount is recognized as expense in the statement of earnings over the vesting period of the option with a corresponding increase to contributed surplus. The Corporation has not incorporated an estimated forfeiture rate for stock options that will not vest, rather the Corporation accounts for actual forfeitures as they occur.

Foreign Currency Translation

The Corporation's foreign operations in the State of Montana, Montana Land and Exploration, Inc., are translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Non-monetary assets are translated at rates in effect on the dates the assets were acquired. Translation gains and losses are included in income.

2. PROPERTY, PLANT AND EQUIPMENT

December 31, 2005	Cost	Accumulated Depletion & Depreciation	Net Book Value
Oil and gas properties	$70,677,241	$32,313,726	$38,363,515
Materials Inventory (at cost)	543,340	–	543,340
Office equipment	216,744	185,039	31,705
	$71,437,325	$32,498,765	$38,938,560

December 31, 2004	Cost	Accumulated Depletion & Depreciation	Net Book Value
Oil and gas properties	$58,357,150	$25,862,072	$32,495,078
Materials Inventory (at cost)	890,938	–	890,938
Office equipment	208,674	146,789	61,885
	$59,456,762	$26,008,861	$33,447,901

The Corporation capitalizes general and administrative costs attributable to acquisition, exploration and development activities. In Canada personnel costs of $216,688 (2004 - $345,600) and general overhead costs of $139,976 (2004 - $184,257) were capitalized. In Montana, personnel costs of $444,645 (2004 - $359,658) and general overhead costs of $11,169 (2004 $75,599) were capitalized.

Unproved Properties

($)	**2005**	2004
Canada	**794,000**	1,550,000
Montana	**6,300,000**	5,600,000

Included in oil and gas properties at December 31, 2005 are costs of $794,000 (2004 - $1,555,000) related to Canadian unproved properties and $6,300,000 (2004 - $5,600,000) related to Montana unproved properties, valued at cost, that have been excluded from costs subject to depletion. In Montana, $543,340 (2004 - $890,938) of materials inventory has also been excluded from the costs subject to depletion.

Ceiling Test

AltaCanada has performed ceiling tests for its Canadian and US geographical segments and no impairment exists at December 31, 2005. The impairment tests were calculated using future prices for the years 2006 to 2010 as follows:

$ CDN	2006	2007	2008	2009	2010	Thereafter
For Canadian Assets:						
Oil $/Bbl	40.03	39.53	38.04	36.55	36.55	39.20
Gas $/Mcf	10.23	8.92	7.71	7.23	6.94	7.25
For US Assets:						
Gas $/Mcf	10.15	8.87	7.68	7.20	6.92	7.24

3. ASSET RETIREMENT OBLIGATIONS

Management has estimated the total future asset retirement obligation based on the Corporation's net ownership interest in all wells and facilities. This includes all estimated costs to dismantle, remove, reclaim and abandon the wells and facilities and the estimated time period during which these costs will be incurred in the future.

	2005	2004
Asset Retirement Obligation, beginning of year	$ **1,214,045**	$ 637,306
Liabilities incurred	**199,168**	312,659
Disposals	**(526,898)**	(211,706)
Accretion expense	**106,831**	69,721
Revision to estimate	**207,287**	406,065
Asset Retirement Obligation, end of year	$ **1,200,433**	$ 1,214,045

The undiscounted amount of estimated cash flows required to settle the obligation is $4.9 million.

The estimated cash flow has been discounted using a credit adjusted risk free rate of 8.0 percent and inflated at 2.0 percent per annum. The expected period until settlement ranges from a minimum of 2 years to a maximum of 40 years.

4. BANK AND OTHER INDEBTEDNESS

	December 31, 2005	December 31, 2004
Revolving Line of Credit	$ 7,583,928	$ 3,755,072
Outstanding Cheques	45,169	9,618
Cash on Deposit	(1,041,157)	(168,373)
Total	$ 6,587,940	$ 3,596,317

In January 2005, AltaCanada entered into a $7.0 million secured development bridge facility. Funds from the bridge facility were used to repay existing bank debt with a Chartered Bank and to fund 2005 capital expenditure programs. Interest was payable monthly in arrears at a rate equal to the prime lending rate plus 3.0 percent. A commitment fee of 1.75 percent was paid on the draw down of the $7.0 million. This bridge facility matured June 30, 2005 and was replaced with an $8.0 million revolving line of credit with a Chartered Bank of which $7.0 million was used to repay the

bridge facility. Interest is calculated on the daily outstanding principal amount at the bank's prime lending rate plus 0 to 0.5 percent relative to the Corporation's debt to cash flow ratio. Indebtedness under the line of credit is repayable on demand and security is provided by a $50.0 million demand debenture representing a first floating charge on all of the Corporation's oil and gas properties and undertakings of the Corporation. The line of credit is subject to periodic review.

Subsequent to December 31, 2005, the Corporation's Banker has provided a letter of waiver regarding the Corporation's year-end working capital deficiency and the Corporation is currently negotiating with the bank to increase the line of credit to $10.0 million.

5. CONVERTIBLE DEBENTURES

	Principal	Shares Issued	Weighted Average Conversion Price
Outstanding December 31, 2003	$ 705,081		
Conversion	(732,581)	1,436,434	$0.51
Redemption – for cash	(4,779)		
Accretion of Discount on Convertible Debentures	10,997		
Equity Portion of Debentures Converted/Redeemed	21,282		
Outstanding December 31, 2004 and 2005	–		

Convertible debentures in an aggregate principal amount of $1,861,427 were issued pursuant to the acquisition of Alberta Selecta Corporation in 2002. The debentures were to mature July 1, 2006 and bore interest at an annual rate of 8 percent payable semi-annually. At the option of the holder, the debentures were convertible to common shares of AltaCanada at a 15 percent discount to the prior 20-day weighted average trading price on the TSX-V, subject to a minimum conversion price of $0.35 per share. In 2004 the remaining convertible debentures were converted; $732,581 principal amount of convertible debentures were converted to 1,436,434 common shares at a conversion price of $0.51 and $4,779 principal amount of convertible debentures were redeemed for cash.

6. CAPITAL STOCK

The Corporation is authorized to issue an unlimited number of common or preferred shares without nominal or par value.

	Shares		Consideration
Outstanding Common Shares December 31, 2003	51,983,024	$	17,995,395
Issued Under Stock Option Plan	290,000		58,000
Issued on Conversion of Convertible Debentures	1,436,434		732,581
Issued Under Warrant Exercise	25,000		18,750
Issued by private placement October 2004	5,753,793		4,430,421
Share Issue Costs, Net of Future Income Taxes of $151,785	–		(300,566)
Outstanding Common Shares December 31, 2004	59,488,251	$	22,934,581
Issued Under Stock Option Plan (average price of $0.26 per common share)	529,593		138,878
Share Issue Costs	–		578
Outstanding Common Shares December 31, 2005	60,017,844	$	23,074,037

At December 31, 2005, the following common shares were reserved for issuance:

	Exercise Price ($)	Equivalent Shares Outstanding (#)	Weighted Average Years to Expiry	Vested Options (#)
Stock Option Plan:	0.30	1,079,593	1.75	1,079,593
	0.56	130,000	4.33	43,333
	0.78	900,407	2.42	900,407
	0.58	250,000	3.42	166,667
	0.63	1,190,000	4.59	430,000
	0.62	210,000	3.67	140,000
	0.60	700,000	4.17	233,333
Total Stock Option Plan	0.57	4,460,000	3.28	2,993,333
Warrants	0.95	2,876,897	0.33	
Total Shares Reserved	0.72	7,336,897	2.12	

On April 30, 2005 4,241,667 warrants issued in 2003 at an exercise price of $0.75, expired unexercised.

Existing warrants at an exercise price of $0.95 have an expiry date of April 27, 2006.

The Corporation has a stock option plan under which it may grant options to its directors, officers, employees, and consultants for up to a maximum of 10 percent of its issued and outstanding common shares at market price at the date of grant for up to a maximum term of five years. A summary of the status of the plan is presented below:

	Number of Options	Weighted Average Exercise Price	Total Value
Balance, December 31, 2003	**2,950,000**	**$ 0.45**	**$ 1,332,891**
Granted	560,000	0.59	332,700
Exercised	(290,000)	0.20	(58,000)
Cancelled	–	–	–
Balance, December 31, 2004	**3,220,000**	**$ 0.50**	**$ 1,607,591**
Granted	2,000,000	0.61	1,228,700
Exercised	(529,593)	0.26	(138,878)
Cancelled	(230,407)	0.67	(153,517)
Balance, December 31, 2005	**4,460,000**	**$ 0.57**	**$ 2,543,896**

In the first quarter, the Corporation granted options to employees to purchase 700,000 common shares of the Corporation at an exercise price of $0.60 per share. In the second quarter, AltaCanada granted 130,000 stock options, at an exercise price of $0.56, to two of the independent directors of the Corporation. In the third quarter, 1,170,000 options were granted to employees and directors at an average exercise price of $0.63.

Of the 4,460,000 options outstanding at December 31, 2005, 2,993,333 are vested and “in-the-money”.

7. STOCK BASED COMPENSATION

Stock Options

The Corporation uses the Black-Scholes option-pricing model to determine the fair value of each option granted and the amount is recognized as additional expense in the statement of earnings over the vesting period of the option.

The fair value of each option granted is estimated on the grant date using the Black-Scholes option-pricing model, using the following average assumptions for options granted:

	2005	2004
Risk Free Interest Rate	**3.31%**	3.39%
Expected Holding period Prior to exercise	**3 years**	3 years
Share Price Volatility	**0.59**	0.60
Estimated Annual Common Share Dividend	**nil**	nil

Contributed Surplus

Balance, December 31, 2003	**$ 566,097**
2004 Stock Based Compensation Expense	303,113
Balance, December 31, 2004	**$ 869,210**
2005 Stock Based Compensation Expense	411,953
Balance, December 31, 2005	**$ 1,281,163**

Stock Bonus

On January 2, 2006, the Corporation committed to issue 200,000 common shares to personnel engaged by the Corporation for the period January 1, 2006 to May 1, 2006. The value of this compensation will be determined by multiplying the number of shares to be issued by the weighted average trading price of the Corporation's shares for the ten day period prior to May 1, 2006.

8. INCOME TAXES

The provision for taxes differs from the result which would be obtained by applying the combined federal and provincial tax rate of 37.62 percent (2004 – 38.87 percent) to earnings before taxes as follows:

		2005		2004
Computed "expected" income tax expense (recovery)	$	**361,714**	$	(156,935)
Federal resource allowance		**(279,952)**		(265,028)
Non-deductible royalties - net of ARTC		**247,573**		243,325
Rate reduction adjustment		**28,373**		(66,475)
Stock based compensation		**154,977**		117,820
Previously unrecognized tax losses		**(509,729)**		–
Other		**(111,219)**		167,005
Actual income tax expense	$	**(108,263)**	$	39,712

Future income tax liability is comprised of the following temporary differences:

		2005		2004
Net book value of property, plant & equipment in excess of tax basis	$	**6,721,898**	$	1,965,552
Asset retirement obligations		**(403,585)**		(408,162)
Share issue costs		**(215,002)**		(316,186)
Non-capital losses carried forward		**(5,307,935)**		(261,822)
Unrealized Gain on Financial Derivatives and Interest		**(336,321)**		(95,620)
Partnership deferrals		**1,502,206**		1,280,389
Future tax liability	$	**1,961,261**	$	2,164,151

The Corporation has the following tax deductions available to reduce future taxable income:

		2005		2004
Canadian oil and gas property expense	$	**1,227,987**	$	4,391,000
Canadian development expense		**2,532,489**		2,802,000
Canadian exploration expense		**160,032**		658,000
Undepreciated capital cost		**1,319,239**		1,853,000
Share issue costs		**639,507**		940,000
Undeducted US capital costs		**11,486,836**		16,993,000
Tax Losses	$	**15,788,028**	$	779,000

9. RELATED PARTY TRANSACTIONS

		2005		2004
Due from Related Parties	$	–	$	6,955

At December 31, 2004 an amount of $6,955 was due from Alberta FutureVest Corporation (AFVC), a corporation controlled by J. Hodel, who was a director and officer of the Corporation and its subsidiary Alberta Selecta Corporation (ASC) until February 4, 2005. This account receivable was a net balance of shared general and administrative costs due from AFVC to the Corporation and joint venture and royalties payable to AFVC by the Corporation, ASC and AltaCanada Energy Partnership (ACEP), a general partnership owned by the Corporation and ASC.

On November 15, 2004, AFVC filed a statement of claim against ASC and ACEP for unpaid royalties. On December 15, 2004, ASC and the Corporation (on behalf of ACEP) filed a statement of defense claiming a right of offset against the outstanding royalties for rent and other items owed to the Corporation, ASC and ACEP in the amount of $116,123. In January, 2005, the Corporation paid $99,637 in royalties into trust pending resolution of the statements of claim.

Pursuant to a settlement agreement dated August 31, 2005, the royalties held in trust were released to AFVC and a net payment of $13,500 was paid to the Corporation by AFVC in net settlement of other amounts owing at that time. The result of this settlement was a net recovery to the Corporation of $49,710 with $66,413 charged to expense in 2005 and a recovery of $116,123 recorded in 2004.

10. FINANCIAL INSTRUMENTS

The Corporation's financial instruments at December 31, 2005 and 2004 are comprised of cash, accounts receivable, accounts payable and accrued liabilities, bank indebtedness. The carrying amounts of these financial instruments approximate their estimated market values.

The Corporation is exposed to credit risk from financial instruments to the extent of non-performance by third parties. A substantial portion of the Corporation's accounts receivable and accounts payable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal credit risks.

The Corporation uses derivative financial instruments to manage its commodity price exposure. Financial instruments used for the year ended December 31, 2005 are:

Natural Gas Costless Collars - Unrealized at December 31, 2005:

Volume (GJ/day)	Volume (GJ)	Cap $/GJ	Floor $/GJ	Term	Realized Gain (Loss)
1,000	152,000	$13.35	$10.00	November 2005 to March 2006	40,033
1,000	152,000	$14.10	$12.00	November 2005 to March 2006	201,155
Total Unrealized Gain					$ 241,188

Natural Gas Costless Collars:- Realized in 2005

Volume (GJ/day)	Volume (GJ)	Cap $/GJ	Floor $/GJ	Term	Realized Gain (Loss)
1,000	92,000	$7.65	$6.50	August 2005 to October 2005	$ (143,908)
1,000	152,000	$14.10	$12.00	November 2005 to March 2006	55,310
1,000	151,000	$8.99	$8.00	November 2004 to March 2005	151,760
1,000	90,000	$7.45	$7.00	January 2005 to March 2005	63,826
Total Realized Gain					$ 126,988

The mark to market value of the hedges outstanding at December 31, 2005 is a financial derivative asset of $241,188. There are no natural gas or oil hedges in place at March 30, 2006.

The Corporation is exposed to foreign exchange fluctuations arising from its US operations. US production is sold into Canada based on a Canadian AECO gas price and thereby mitigating its foreign exchange risk on revenues. The Corporation's US capital expenditures are subject to foreign exchange risk. At March 30, 2006 no foreign exchange hedges are in place.

The Corporation is exposed to interest rate risks on bank indebtedness with a floating interest rate. A one percent change in interest rates would result in a change of $65,879 to interest expense based on bank indebtedness at December 31, 2005.

11. COMMITMENTS

The Corporation leases office space and compressors. Payments under non-cancellable operating leases with terms of one year or more are as follows:

2006	$	503,795
2007		282,727
2008		136,278
2009		–
2010		–
Total	$	922,800

12. SEGMENTED INFORMATION

The Corporation's geographical segmented information is as follows:

	Year ended December 31, 2005		
	Montana	Canada	Total
Production (BOE/d)	298	366	664
Total Revenue ($)	5,795,862	6,711,244	12,507,106
Net Earnings (Loss) ($)	1,249,774	(180,016)	1,069,758
Property, Plant & Equipment ($)	27,022,069	11,916,491	38,938,560
Total Assets ($)	29,233,113	14,778,526	44,011,639
2005 Net Capital Expenditures ($)	10,178,156	(795,324)	9,382,832

	Year ended December 31, 2004		
	Montana	Canada	Total
Production (BOE/d)	43	406	449
Total Revenue ($)	705,980	5,707,375	6,413,355
Net Earnings (Loss) ($)	135,705	(579,131)	(443,426)
Property, Plant & Equipment ($)	18,215,117	15,232,784	33,447,901
Total Assets ($)	18,980,177	17,379,551	36,359,728
2004 Net Capital Expenditures ($)	10,634,271	(649,702)	9,984,569

BOARD OF DIRECTORS

* Member of Audit Committee

CHARLES V. SELBY B.SC. (HONS.) LLB, P.ENG.
Chairman, Chief Financial Officer and Director

Mr. Selby has 30 years of involvement in all aspects of the oil and gas industry. He has considerable experience in the negotiation, structuring and financing of domestic and international transactions. Mr. Selby was employed with Chevron Standard in Alberta and in the Kingdom of Saudi Arabia, and practiced law with two law firms in Calgary for ten years prior to pursuing independent professional and investment activities in August 1994 as President of Selby Professional Corporation. He is Vice President and Corporate Secretary of Pengrowth Corporation, the administrator of Pengrowth Energy Trust, a public trust listed on The Toronto Stock Exchange and the New York Stock Exchange. Mr. Selby is a also a director and CFO of Vecta Energy Corporation, a director of the Qwest Energy Group of Companies, Energy Exploration Technologies Inc., Transco Resources Corp., and Interex Oilfield Services Ltd., and the trustee of EOG Saskatchewan Trust.

DONALD E. FOULKES, B.SC, P.GEOL.
President, Chief Executive Officer and Director

Mr. Foulkes has been a director and the President of AltaCanada Energy Corp. since September 2002. Prior to joining AltaCanada, Mr. Foulkes was the Chairman of the Board of Bushmills Energy Corp., an oil and gas exploration company, until January 2003. Mr. Foulkes was with Causeway Energy Corporation, an oil and gas exploration and production company, from 1995 to 2001, where he held the position of President from 1995 until 1998 when he became the Chief Executive Officer. From 1992 to 1995, Mr. Foulkes was the President of Highridge Exploration Ltd., and from 1988 to 1992 he was the President of Union Pacific Resources Inc., a private oil and gas company. Mr. Foulkes is a professional geologist and received a Bachelor of Science degree in Geology from the University of Calgary in 1970 and is a director of Canada Southern Petroleum Ltd.

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MICHAEL J. HIBBERD, BA, MBA, LL.B.
Director *

Mr. Hibberd has extensive capital markets and mergers and acquisitions experience. He spent twelve years with Scotia McLeod Inc. in Toronto and Calgary and was Senior Vice-President and Director in corporate finance when he left in early 1995 to establish his own corporate finance consulting business (MJH Services Inc.). Mr. Hibberd serves on several boards of TSX and TSX.V listed companies and acts as a financial consultant to a number of Calgary based companies with North American and international oil and gas operations.

JOHN R. MOORE, BASc, P.ENG.
Director *

Mr. Moore has over forty years of experience in oil and gas engineering, operations and management, with emphasis on property evaluation and development. This experience was primarily with Gulf Canada Resources and Dome Petroleum Limited, where he served as Vice-President of Exploitation until leaving the latter company in 1988. Subsequently, he established J.R. Moore & Associates Ltd. (a private consulting firm), and until 1999 was also actively involved with The Eikon Group Inc., Eden Exploration Ltd., and Alma Oil & Gas Ltd. Mr. Moore is now retired.

ROLF GEHRIGER
Director

Since 1995 Mr. Gehriger has been principal of Gehriger Rechtsanwälte, a law firm based in Kreuzlingen, Switzerland. He achieved a law degree in 1993 from the University of Bern, Switzerland, and specializes in the areas of commercial and corporate law.

FRANK J.D. SAYER, BBA, MBA
Director *

Mr. Sayer is an independent businessman and corporate director. He spent 25 years in investment banking with Wood Gundy Ltd., Mcleod Young Weir Ltd., and Sayer Securities Ltd. Prior to this he worked in the oil industry at Chevron Standard Ltd., Ashland Oil Canada Ltd., and Kaiser Oil Ltd. Mr. Sayer presently serves on the investment committees of the Alberta Teachers' Retirement Fund Board and The Calgary Foundation.

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